CANADIAN
ENERGY
RESEARCH
INSTITUTE

3512 - 33 ST. N.W., Calgary, Alberta — T2L 2A6

Phone: (403) 282-1231

WORKING PAPER 81-2

NATURAL GAS PRICING IN CANADA: AN ECONOMIC ANALYSIS

A. J. NIXON

OCTOBER 1981

Working papers are distributed by the Canadian Energy Research Institute in limited numbers. They represent the results of work in progress and are made available in this preliminary form both for information and to obtain comments.

PREFACE

This working paper is an unabridged reproduction of the author's recently completed MA thesis at the University of Calgary. The research began in mid-1980 while Ms. Nixon was a member of the Institute staff and was completed in June of 1981. Only minor clerical modifications have been made to the format of the text. In light of the length and theoretical nature of the thesis, its overall findings have been highlighted with the inclusion of an Executive Summary written by Douglas J. Haughey, CERI staff economist.

Because of the purpose for which it was written, this paper is necessarily somewhat theoretical in emphasis. It does, however, provide useful insight into some of the problems related to gas pricing. For that reason we felt that it would be useful to circulate to interested parties in government and industry. The views expressed herein are those of the author and may not reflect those of CERI economists or the Institute's sponsors.

EXECUTIVE SUMMARY

The pricing of natural gas is a critical ingredient in Canada's energy strategy. Government policies related to natural gas price formation will affect energy supply and demand, the distribution of energy-related economic rents, and the whole question of social welfare and resource exploitation.

This paper addresses these issues through analysis of various natural gas pricing policies. The analysis is based on economic price theory applied to the natural gas industry.

The major points discussed are summarized below.

1. At present, significant shut-in natural gas capacity exists in Canada. Gross additions to reserves have been 3.5 Tcf per year from 1960 to 1978. During this period, marketed production of Alberta natural gas increased from 327 Bcf to 2117 Bcf, an increase not large enough to offset reserve additions. Expansion of natural gas markets during this period was accomplished in large part by producers accepting low gas prices to facilitate market penetration outside of Alberta.

2. Average natural gas prices have increased six fold in real terms from 1960 to 1978. The majority of these gains occurred after the federal-provincial pricing agreement in 1975. In nominal terms, plant gate prices only increased from 9.6 to 27.4 cents per Mcf in fourteen years, compared with a four year post agreement jump to 142.2 cents per Mcf in 1978.

3. Large economies of scale related to pipeline transportation of natural gas are conducive to the development of 'natural monopoly', an argument that is often used to exonerate utility regulation. If such a monopoly firm is regulated as a common carrier (i.e., rate of return regulation), and provided there are several

producers selling gas and several distributors buying it, then price formation may be achieved in a fairly competitive manner.

4. Even with regulated common carriers, the natural gas industry is still a quasi-monopsony characterized by a large number of sellers and relatively few buyers. Currently only two buyers control nearly 80 percent of gas reserves available for removal from Alberta. This quasi-monopsonistic nature of the industry can have a definite effect upon the determination of prices.

5. The presence of monopsony (before the 1975 pricing regulations) resulted in the determination of producer prices and natural gas production below competitive levels. As a result, total social welfare was reduced.

6. This combination of lower producer prices and production volumes would theoretically reduce exploration and cause the long run supply curve to shift to the left as reserve depletion occurs.

7. With competition between natural gas buyers severely impeded, the Alberta government designed 'commodity value' pricing legislation to approximate the impact that normal competition might have had on natural gas prices. Within Alberta, legislation allows for arbitrated settlements of natural gas pricing disputes through calculation of the gas commodity value. Commodity value pricing sets the price of natural gas as the weighted average price per thermal unit of the competitive alternative energy source in various end use markets after adjustments are made for relative fuel efficiency. This paper discusses a method to calculate the burner-tip commodity value as a function of:

    - consumption weights of end uses;
    - delivered prices of competing fuels;
    - heating value of competing fuels;
    - equipment utilization efficiency; and
    - equipment costs.

    Such a formula also has applicability for calculation of natural gas incentive pricing in new markets.

8. The commodity value method of price determination should only be used to correct short run market distortions, and will be difficult to operate due to data limitations. In the long-term, pricing natural gas based on the supply/demand forces related to other energy commodities is not theoretically correct. Price should be determined by the supply/demand relationships for natural gas itself. The use of natural gas in non-thermal uses such as petrochemicals will also decrease the validity of commodity value pricing based on heating uses because the real non-energy value of the gas is not determined.

9. In November, 1975 the federal government, in concurrence with the Alberta government, set the price of natural gas at 85 percent of the Btu equivalent crude oil price. The recent energy agreement provides for a subsequent reduction to 65 percent. Such Btu equivalence pricing, however, may be criticized on the same grounds as commodity value pricing. The supply/demand relationship for natural gas itself should be the major determinant of price. Therefore, Btu equivalence pricing is not theoretically correct in the long run because it does not reflect the scarcity or special qualities of natural gas.

10. Incentive pricing of natural gas involves lower regulated prices in areas where conversion to natural gas is desired. The pricing of this gas in expansion markets could be similar to commodity value pricing described above with the inclusion of conversion costs as another determinant of price.

11. A gradual deregulation of domestic natural gas prices is suggested. It would result in an overall net gain to producers and consumers. This net gain would be a function of the magnitude of change in natural gas prices as well as the shape of the producer's supply curve and consumer's demand curve. Producers alone may or may not gain, therefore, the effect on the long-run supply curve is unknown.

12. Even allowing natural gas prices to fall to equilibrium levels will result in a misallocation of resources if crude oil prices

were to remain artificially low. Domestic oil prices should rise to world levels, enhancing the attractiveness of natural gas, reducing oil demand, and stimulating oil supply.

13. Large resource price increases will bring windfall profits to producers. Taxation of these rents is likely. This system of taxation must recognize the difference in rents accruing to various energy projects and activities, and guard against reduced supply-side investment due to onerous tax regimes.

14. The dual price system for domestic and export sales is theoretically sound by maximizing domestic welfare and charging premium prices in the export market. The acceptability of the current natural gas export price has not been addressed, however.

ACKNOWLEDGEMENTS

I would like to thank Mr. Campbell Watkins, my supervisor, for his assistance and guidance throughout the writing of this thesis. His advice and comments were sincerely appreciated.

This research was supported by the Canadian Energy Research Institute. I would like to thank various members of the Institute for their helpful comments in the initial stages of this thesis. Also, I wish to thank Mrs. Shirley Ingstrup for her unending patience in typing several drafts of this manuscript.

DEDICATION

To my parents,

Joan B. Nixon

and

W. G. (Nick) Nixon

TABLE OF CONTENTS

PREFACE..iii

EXECUTIVE SUMMARY..v

ACKNOWLEDGEMENTS...ix

DEDICATION...x

TABLE OF CONTENTS..xi

LIST OF FIGURES..xiv

LIST OF TABLES...xiv

INTRODUCTION...1

CHAPTER 1: KEY ASPECTS OF THE CANADIAN NATURAL GAS INDUSTRY..........3

- 1.1 Introduction..3
- 1.2 Development of Gas Supply.............................3
- 1.3 Development of Marketing and Pricing..................5
    - 1.3.1 The Marketing of Alberta Natural Gas..........5
    - 1.3.2 The Canadian Natural Gas Delivery System......8
    - 1.3.3 The Development of Canadian Natural Gas Pricing..........8
- 1.4 Industry Structure....................................13
- 1.5 Government Regulation of the Industry.................15
- 1.6 Regulatory Bodies Influencing the Canadian Natural Gas Industry..........17
    - 1.6.1 Alberta Energy Resources Conservation Board..........17
    - 1.6.2 National Energy Board.........................17
    - 1.6.3 Federal Power Commission......................18
- 1.7 Development of Regulation as it Affects Natural Gas Pricing..........19

Footnotes..25

CHAPTER 2: PRICE THEORY IN THE CONTEXT OF THE NATURAL GAS INDUSTRY....................................29

2.1 Introduction....................................29

2.2 The Role of Price....................................29

2.3 Background for Analysis....................................30

2.4 Monopsonistic Exploitation of a Resource...........34

2.5 Effects of Monopsonistic Price Formation...........38

2.6 Price Discrimination....................................44

2.6.1 A Policy of Free Trade....................45

2.6.2 Price Discrimination: The Profit Maximizing Objective....................48

2.6.3 Price Discrimination: The National Welfare Maximizing Objective................51

Footnotes....................................56

CHAPTER 3: THE PRICING OF CANADIAN NATURAL GAS....................61

3.1 Introduction....................................61

3.2 Net Back Pricing....................................62

3.3 Competitive Pricing....................................62

3.4 Btu Equivalence Pricing....................................65

3.5 Commodity Value Pricing....................................67

3.5.1 Commodity Value Legislation.................67

3.5.2 General Methodology for Determining Commodity Value....................69

3.5.3 Hypothetical Commodity Value Calculation....................73

3.5.4 Commodity Value Pricing: A Surrogate for Competition?....................77

3.5.5 Commodity Value Pricing: The Impact of Specialized Consumption Patterns............81

3.5.6 Commodity Value Pricing: Conclusions.......87

3.6 Rolled-In Pricing....................................87

3.7 Price Discrimination....................................89
3.7.1 A System of Dual-Pricing...................90
3.7.2 Incentive Pricing...........................92
Footnotes...94
CHAPTER 4: SOME CONCLUSIONS AND POLICY IMPLICATIONS..............99
4.1 Introduction...99
4.2 Legislated Natural Gas Prices......................99
4.2.1 Btu Equivalence Pricing...................99
4.2.2 Commodity Value Pricing...................100
4.2.3 Incentive Pricing.........................101
4.3 A Policy of Deregulation and Escalation..........101
4.4 Addressing the Issue of Windfall Profits.........106
4.5 Implications for Export Policy....................108
Footnotes...109
BIBLIOGRAPHY...111

FIGURES

1.1 Initial Established Marketable Natural Gas Reserves, Canada, Conventional Producing Areas, 1959-1978........................7

1.2 Canadian Natural Gas Pipeline System and Proposed Extensions...9

2.1 Monopsony Price Formation..36

2.2 The Effects of Monopsonistic Price Formation..................40

2.3 An Illustration of Possible Extremes in Export Policy.........46

2.4 Price Discrimination: The Profit Maximizing Objective........49

2.5 A Dual-Price System Governed by a Strategy of National Welfare Maximization.......................................53

3.1 Determination of the Alberta Field Price for Natural Gas......63

3.2 Determination of a Uniform Price for Perfect Substitutes......78

3.3 Consumer Equilibrium - Specialized Consumption................83

4.1 The Effects of Competitive Price Formation...................102

TABLES

1.1 Marketed Production of Alberta Natural Gas, 1954-1978..........6

1.2 Western Canada Average Prices of Natural Gas, 1947-1978.......11

1.3 Total Reserves Available for Export from Alberta, December 31, 1979...14

INTRODUCTION

The issue of natural gas pricing has been the focus of substantial political and public debate, involving not only provincial and federal interests but foreign, principally United States', interests as well.

Up until the mid-1970s natural gas prices were primarily determined via market forces (or at least without government intervention) and government involvement was primarily restricted to the adjudication of a few arbitrations. For various reasons these market forces provided a less than robust competitive environment, with the result that prices were determined at levels below competitive market values. The 1973-74 dramatic quadrupling of world crude oil prices and the associated rise in the Canadian domestic oil price--a close substitute for natural gas in many end uses--exacerbated the undervaluation of natural gas.

In November of 1975, formal recognition of the lack of competition in the Canadian natural gas industry came with the entry of government determined natural gas prices. On that date the federal government in concurrence with the Alberta government legislated a price for Canadian natural gas. This legislation effectively tied the natural gas price to the domestic crude oil price. As such, the legislation intended to simulate the impact of normal competition, then thought to be absent, upon natural gas prices. Also in November 1975, a natural gas export price was set, predicated on the value of crude oil imported in eastern Canada.

Since that date (November 1975), government has remained actively involved in the determination of natural gas prices on both fronts: domestic and export. The domestic price of natural gas continues to be determined at a stipulated fraction of the domestic crude oil price. In turn the latter is set by government at less than the world oil price. The price of natural gas for export to the United States remains determined via government legislation.

Government regulation of a vital resource is subject to public scrutiny and debate. Serious thought should be given to the validity of the current natural gas pricing arrangement. Should the conditions in one market be allowed to dictate prices in other markets, and if so under what conditions should such a pricing mechanism be permitted to prevail? What are the implications for Canada of the maintenance of a dual-price system such as that which exists for the domestic and foreign natural gas markets? Does, in fact, the potential presence of monopsony power prescribe government regulation of prices? It is towards these issues which this thesis is directed. By tracing the historic relationship between various pricing mechanisms and market circumstances, the thesis attempts to resolve some of these questions.

The contents of the study are organized as follows. The first two chapters provide a general background to the analysis. The organization and development of the Canadian natural gas industry are presented in Chapter 1. Attention is focused upon the particular structure of the natural gas industry and the regulatory bodies affecting the industry. Chapter 2 is a theoretical analysis of selected aspects in price theory, discussing the importance of 'price' and the effects of various market arrangements upon its determination, especially monopsony and dual-price systems. Various concepts used in natural gas pricing are discussed and analyzed in Chapter 3; concurrently, the theoretical analysis of Chapter 2 is employed to characterize the natural gas pricing regimes which have prevailed. The final chapter, Chapter 4, discusses some of the policy implications of the analysis.

CHAPTER 1

KEY ASPECTS OF THE CANADIAN NATURAL GAS INDUSTRY

1.1 Introduction

To facilitate analysis of natural gas pricing, some key aspects of the natural gas industry are described in this chapter. In particular, the chapter focuses upon the development of natural gas supplies, markets and pipelines as well as the historical trend in natural gas prices. Industry structure and the role of government regulation are also discussed. Since about 85 percent of Canadian natural gas is produced within Alberta, with the rest mainly in British Columbia, the main focus in the chapter is on the Alberta natural gas industry.

1.2 Development of Gas Supply

Until the 1950s, the history of the Alberta natural gas industry had been dismal. Natural gas was found incidental to the discovery of oil and then the discovery of gas was only slightly better than a dry hole. Natural gas prices were low and the transportation network necessary to move gas to market was not in place. These circumstances together resulted in considerable volumes of natural gas being shut-in, flared or possibly sold in local markets at depressed prices. Nowhere is this situation better illustrated than when, between 1921 and 1945, gas sold at a nominal price of $0.02 per thousand cubic feet (Mcf) to the City of Calgary from the Turner Valley field and about a trillion cubic feet (Tcf) of gas was flared.[1]

With the exceptions of Turner Valley and Jumping Pound, prior to the Leduc discovery most natural gas was found in the eastern plains. With the discovery of oil at Leduc in 1947, exploration activity was accelerated which, as a consequence, produced major natural gas finds within 3 to 4 years at Leduc, Pincher Creek, Cessford and Stettler, to name only a few.[2]

In Alberta, the life index[3] of natural gas at the time of the Leduc discovery was 153 years which reflected an annual marketed gas production of 33.4 Bcf from a resource base of 5.1 Tcf.[4] Four years later, the natural gas life index increased to 193 years, which reflected a 58.0 Bcf annual marketed production rate from an 11.2 Tcf natural gas resource base.

By 1956, despite a large increase in Alberta's marketed gas production, the natural gas life index rose to 199 years.[5] Large oil fields were being discovered during the 1950s, and gas was again found incidental to the discovery of oil. However, the industry in general was still not interested in gas as the low prices and long marketing delays meant poor cash flow generation.

By the end of 1961, annual marketed gas production from Alberta totalled 408 Bcf, of which 25 percent was destined to the United States. In fact by 1961 Alberta out-of-province movements of natural gas were more than twelve times their total four years beforehand.. The natural gas life index was significantly shortened to 74 years, despite the large accumulation of natural gas inventories.[6]

Annual marketed gas production from Alberta has continued to increase steadily, as has Alberta consumption of that gas. However, Alberta consumption currently constitutes a much smaller percentage of total production than it did throughout the 1950s and 1960s. For example, in 1971 Alberta consumption constituted only 15 percent of total Alberta marketed production whereas in 1959 over 50 percent was consumed within Alberta.

In 1978, the most recent year for which national data are available, Canada's total marketed natural gas production was 2474 billion cubic feet (Bcf) of which Alberta produced about 2100 Bcf. British Columbia, the next largest producer, produced about 300 Bcf of Canada's total production. In that same year, natural gas exports to the United States were 881 Bcf, which represented 36 percent of total

Canadian production. Of these total exports, 724 Bcf emanated from Alberta, with the remainder coming from British Columbia. Table 1.1 summarizes information on Alberta natural gas production, consumption and exports between 1954 and 1978.

Figure 1.1 illustrates the growth of initial established reserves of Canadian natural gas from 1959 to 1978. The straight line on the chart represents gross additions to reserves of approximately 3.5 Tcf per year.[7] The higher additions especially in 1977 and 1978, are associated with a substantially increased drilling effort.[8]

The most recent (May 1980) estimate of the life index for Alberta natural gas puts it at 25 years, a considerable reduction from levels prevailing in earlier decades. This is attributable to increased annual rates of production outweighing reserve additions.

1.3 Development of Marketing and Pricing

1.3.1 The Marketing of Alberta Natural Gas

Within Alberta, the Alberta Gas Trunk Line (AGTL, now NOVA), a regulated common carrier,[9] transports gas for removal from the various natural gas fields within the province to provincial border crossing points. Generally speaking, gas flowing east enters the Plains portion of the transmission system, and gas flowing south and west enters the Foothills portion of the system. The integration of these two sub-systems with the main portion of the Trunk Line system permits some interchange of gas between the Plains and Foothills systems. As a common carrier the Trunk Line transports gas under contract and operates on a cost of service basis.

The principal purchasers of gas within Alberta include the major Alberta utilities, Alberta industry and the permit holders for gas removal from the province. The major permit holders include TransCanada, Alberta and Southern, Westcoast Transmission and Canadian Montana. These purchaser transmission companies negotiate directly with natural gas producers to obtain long term purchase contracts.

TABLE 1.1

MARKETED PRODUCTION OF ALBERTA NATURAL GAS
1954-1978

Year	Total	Alberta Consumption		Exports[a]	
	Bcf	Bcf	Percent	Bcf	Percent
1954	89	81	91	8	9
1955	108	96	89	12	11
1956	116	104	90	12	10
1957	136	114	83	22	17
1958	189	117	62	72	38
1959	255	132	52	123	48
1960	327	141	43	186	57
1961	408	142	35	266	65
1962	608	153	25	455	75
1963	674	161	24	513	76
1964	741	164	22	577	78
1965	803	178	22	625	78
1966	848	187	22	661	78
1967	919	202	22	717	78
1968	1041	208	20	833	80
1969	1217	231	19	986	81
1970	1499	233	16	1266	84
1971	1668	248	15	1420	85
1972	1857	269	14	1588	86
1973	1958	281	14	1677	86
1974	1997	297	15	1700	85
1975	2034	307	15	1727	85
1976	2121	320	15	1801	85
1977	2334	388	17	1946	83
1978	2117	426	20	1821	80

SOURCE: Canada, Statistics Canada, The Crude Petroleum and Natural Gas Industry, Statistics Canada Catalogue No. 26-213.

[a] Exports here refers to out-of-province movements of gas, whether or not this gas be destined to U.S. markets.

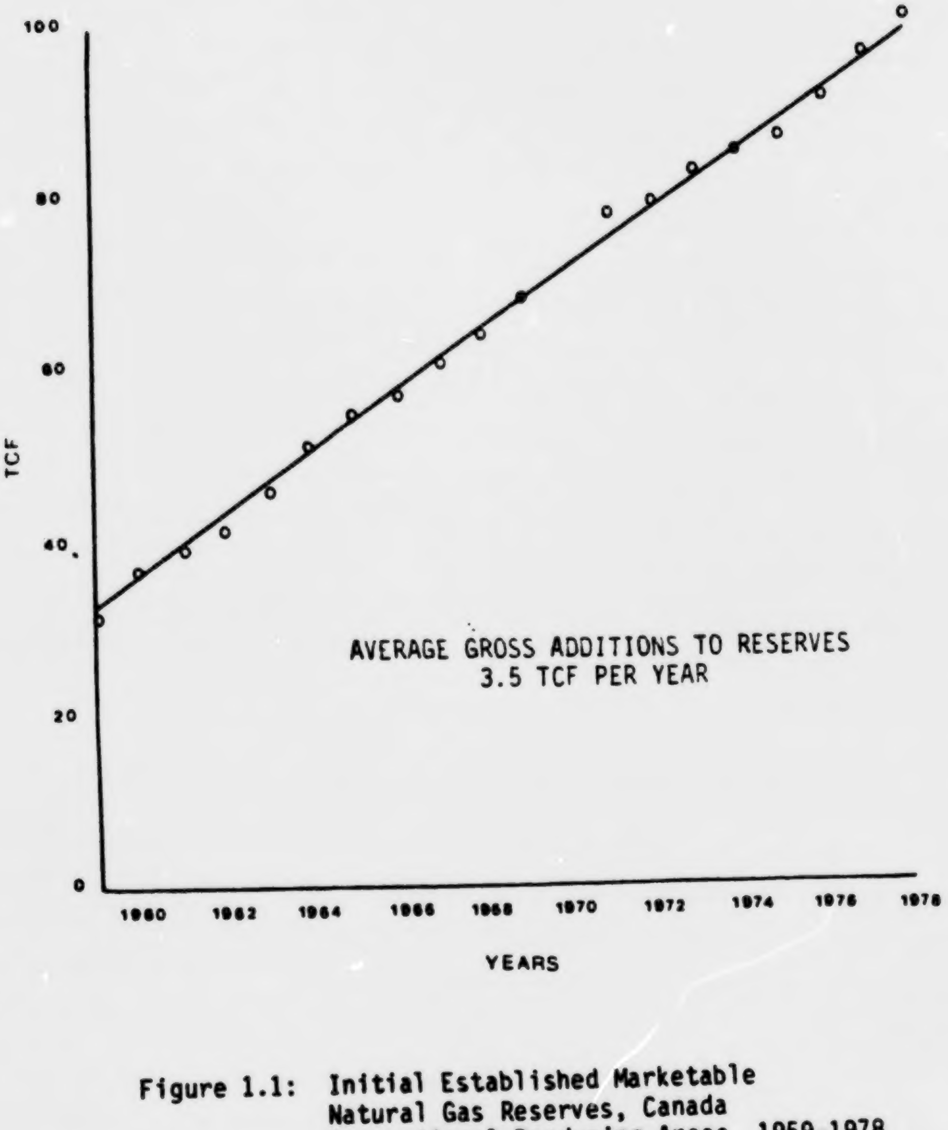


Figure 1.1: Initial Established Marketable Natural Gas Reserves, Canada Conventional Producing Areas, 1959-1978

Major Alberta utilities and some industrial customers, as well as purchasing gas on a long term contract basis, may buy reserves still in the ground with the right to produce them at their discretion.

1.3.2 The Canadian Natural Gas Delivery System

Figure 1.2 shows the current Canadian natural gas pipeline system and proposed extensions, including the proposed TransCanada (TCPL) and Quebec and Maritimes (Q & M) pipeline which is an eastern extension of the TransCanada Pipeline system to the Maritimes. The National Energy Board has approved the extension to Quebec City which is expected to provide service by 1981.[10] The remainder of the extension to Halifax, Nova Scotia has been denied approval to await determination of the availability of oil and gas from east coast offshore areas. However, the Q & M-TCPL application is again under review. An extension of the gas pipeline system west to Vancouver Island is also anticipated. Moreover, Figure 1.2 identifies some possible frontier area lines, including the proposed Alaska and Dempster Highway projects to bring down Arctic gas from the Beaufort and Mackenzie Delta areas. Regulatory problems have imposed long delays on these projects. Also shown is the proposed Arctic Pilot Project to bring down gas from Melville Island, N.W.T. to eastern Canada. This project would be a year-round operation requiring the construction and operaton of a 100 mile pipeline on Melville Island and two ice-breaking LNG tankers.

1.3.3 The Development of Canadian Natural Gas Pricing

During the 1950s there was a significant increase in Alberta's marketed gas production both for domestic and export use as shown in Table 1.1. In 1952, Westcoast Transmission acquired permission to export natural gas to British Columbia and the Pacific Northwest United States.

In 1954, TransCanada Pipelines acquired the permit to transport natural gas as far east as Montreal. After what was thought to be a result of sacrifices on the part of gas producers, a pipeline to eastern Canada was built.[11] This sacrifice was the acceptance of low

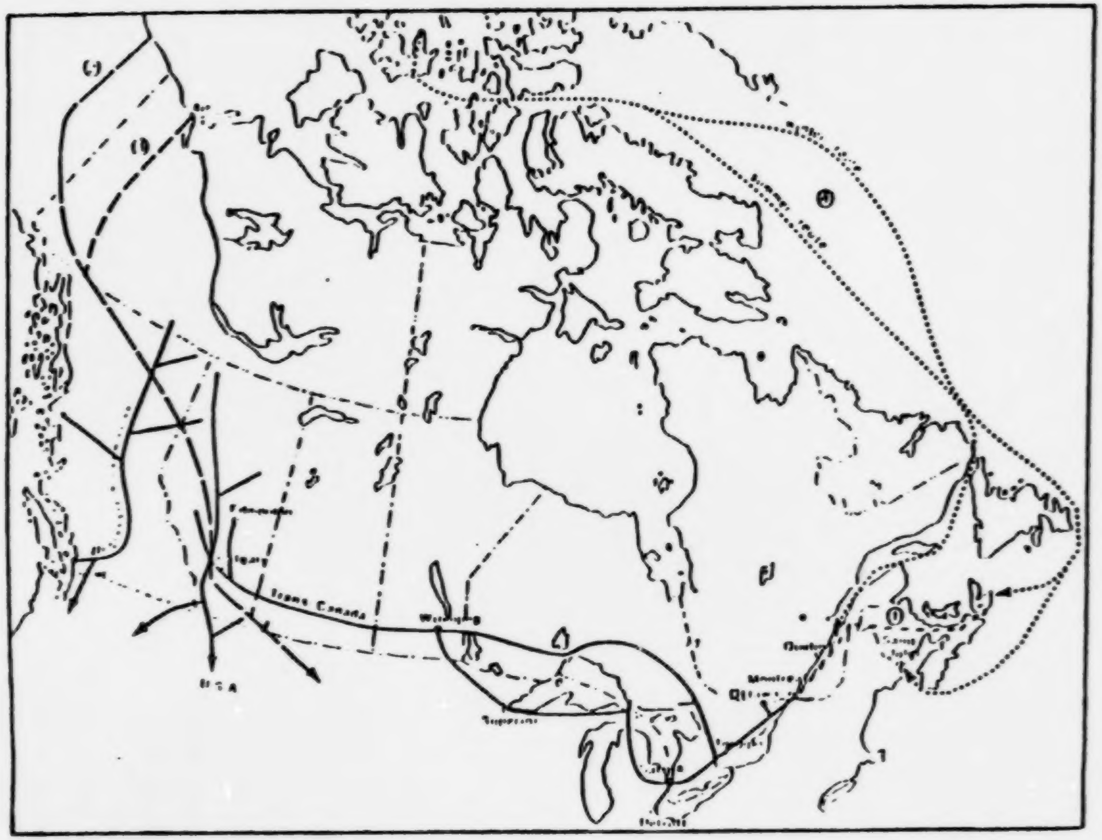

②
③
④
①
Trans Canada
U.S.A.
Winnipeg
Quebec
Montreal

Figure 1.2: Canadian Natural Gas Pipeline System and Proposed Extensions

Notes:
① Q&M Pipeline
② Alaska Highway Project
③ Dempster Highway Project
④ Arctic Pilot Project

gas prices and 27 year contracts. Between 1952 and 1959, as is shown in Table 1.2, the average natural gas wellhead price (real 1971 $) fell from $0.15/Mcf to $0.13/Mcf.[12]

Under competition the wellhead price should equal the market value of gas, determined at the point of consumption by competitive forces, less distributor and transporter margins. Since the initial years of pipeline operation do not fully utilize the transporter's facilities, the unit costs of transportation (as expressed by tariffs subject to regulation) are initially high. Thus, in order to facilitate market penetration and achieve the desired level of pipeline capacity utilization, producers are often placed in a position whereby they are required to accept initial gas prices which are below the long run value of the gas. The producers' refusal to accept such pricing arrangements could jeopardize the economic viability of the project. Low initial prices are accepted by the producer on the prospective view that higher field value will be achieved some time in the future. The inclusion of renegotiation and favoured nation clauses plus the provision for periodic escalation in natural gas prices in natural gas contracts (refer to Chapter 2 for definitions of these clauses) provided the flexibility to escalate the gas price from initially low base prices.

In 1959, Alberta and Southern was granted permission to export gas to northern California, and in 1961 this export line to the United States went into operation. Alberta and Southern owns no pipeline facilities. It relies on the transmission services of Trunk Line and Alberta Natural Gas Company (an affiliate of Alberta and Southern) to move its gas through Alberta and British Columbia to the U.S. border.

The granting of additional exports to the United States during the 1960s added a competitive factor to the Canadian natural gas market which at that time was suffering from a lack of markets. From 1961 to 1964, the average wellhead natural gas price (real 1971 $) increased annually at an average rate of 4.4 percent. In contrast, the same price over the 1950s had fallen by 1.3 percent annually. A portion of the increase over the 1960s is attributable to declining pipeline

TABLE 1.2

WESTERN CANADA AVERAGE PRICES OF NATURAL GAS[a]
1947-1978

Year	Natural Gas Average Wellhead/ Plant Gate Price (¢/Mcf) Nominal	Real[b]
1947	6.7	15.4
1948	6.5	13.1
1949	6.3	12.2
1950	5.9	11.2
1951	6.2	10.5
1952	9.4	15.3
1953	9.3	15.0
1954	9.3	14.7
1955	9.4	14.8
1956	9.6	14.5
1957	10.0	14.7
1958	9.5	13.7
1959	9.0	12.7
1960	9.6	13.3
1961	11.5	15.9
1962	12.1	16.5
1963	13.3	17.8
1964	13.9	18.1
1965	13.7	17.3
1966	14.4	17.4
1967	14.8	17.2
1968	14.8	16.7
1969	14.7	15.9
1970	15.2	15.7
1971	15.0	15.0
1972	15.8	15.0
1973	17.4	15.2
1974	27.4	20.7
1975[c]	55.7	38.1
1976	86.9	54.1
1977	119.7	69.7
1978	142.2	77.8

SOURCE: Canadian Petroleum Association, Statistical Handbook, Section VI, Table 1.

[a] Includes Alberta, British Columbia, Manitoba, Saskatchewan and Territories.

[b] Deflated by GNE Implicit Price Index, 1971 = 100.

[c] Denotes the initial year that the federal government legislated the natural gas price at its 85 percent crude oil Btu equivalence.

tariffs as throughput increased. Most natural gas contracts provide for periodic escalation in natural gas field prices, sharing with the producer the anticipated improvement in the long term financial position of the pipeline as the line becomes more fully utilized.

During the 1960s the price of sulphur increased. This higher price for a natural gas by-product as well as the prospect of generating more natural gas exports have been credited with triggering increased exploratory activity oriented towards the search for natural gas.[13] Between 1958 and 1964 gas reserves grew rapidly and with it the optimism of additional gas exports. By the late 1960s, the United States was seeking to import Canadian natural gas to relieve an exigent natural gas shortage in that country. The United States gas shortage was initiated by a mendaciously low wellhead ceiling price on natural gas regulated by the Federal Power Commission (FPC) which forestalled incremental production while stimulating demand.[14]

In 1969, Consolidated Natural Gas, an American utility company, entered the Canadian natural gas market, further increasing prices, offering a shortened contract period of 20 years and providing cash advances against future product. In the vernacular, these cash advances are called 'prepayments', and in essence they are interest free loans intended to encourage the establishment and development of new reserves. They are usually paid back during the early years of gas delivery. In 1972 these prepayments amounted to $200 million,[15] and as such they provide an important source of financing for the industry. One reason why these prepayments have been so large is that the FPC in the United States has permitted utility companies to work these payments into their base rates. Prepayment furnishes these utility companies with proprietary rights to gas which is discovered. Recognition of these proprietary rights is expected to exert pressure on policy makers when permission is sought to export gas or build pipelines.

In 1970 additional export permits were granted by the National Energy Board (NEB). However, these were only a fraction of the requested permits. By 1971, the NEB refused further requests to export gas, deeming no surplus to exist. Thus, the increased competition in the United States for incremental natural gas supplies was only partly transmitted to the Canadian natural gas market, and as a result competition in the Alberta gas market was severely restricted. The occlusion from pressure generated in the United States gas market left competition so restricted in the Canadian gas market that it has been characterized as monopsonistic in nature, with TransCanada Pipeline's monopsonistic powers maintaining average natural gas field prices below competitive levels.[16]

In 1972, Pan Alberta Gas Ltd. entered the market as a new gas buyer providing increased pressures on natural gas prices. It offered initial field prices of $0.38/Mcf at a time when the average field price was $0.15/Mcf (see Table 1.2).

Over the next few years the rapidly rising price of gas's closest substitute, crude oil, exacerbated the undervaluation of gas as TransCanada was able to maintain its quasi-monopsonistic position in the natural gas market. The following section (Section 1.4) which addresses industry structure, discusses in more detail the quasi-monopsonistic position granted TransCanada Pipelines in the Alberta natural gas industry. At a time when the world was up in arms about an 'international energy crisis' (1973) natural gas was sold in Canada at prices which were considerably below prices prevailing ten years earlier (real 1971 $).

1.4 Industry Structure

The organization of markets may differ in several dimensions: number of buyers and sellers, conditions of entry, degree of interdependence and risk, etc. Various combinations of these dimensions are possible, each having definite consequences for prices.

In the Canadian natural gas industry producers are numerous[17] although there are only a few pipeline companies, two of which dominate gas purchasing. In British Columbia, Westcoast Transmission is the only pipeline company purchasing natural gas production. It does so from the British Columbia Petroleum Corporation (BCPC), which in turn is the sole buyer of gas from B.C. producers. The prices paid to B.C. producers and charged to Westcoast Transmission are determined by the BCPC. In Alberta, TransCanada Pipelines dominates gas purchasing, followed by Alberta and Southern. Together these two pipeline companies purchase the major portion of gas produced in Alberta. The majority of Alberta requirements are served by the two utilities: Canadian Western Natural Gas (CWNG) and Northwestern Utilities Limited (NUL). In 1978, Alberta requirements were only 20 percent of total Alberta production. Thus, buyer concentration in Alberta is mainly on reserves committed for removal from the province. At the end of 1979 total reserves available for export from the province were divided amongst the pipeline companies as follows:

TABLE 1.3

TOTAL RESERVES AVAILABLE FOR EXPORT FROM ALBERTA, DECEMBER 31, 1979

	Trillions of Cubic Feet	Percent of Total
TransCanada	19.1	54
Alberta and Southern	9.0	25
Westcoast Transmission	2.5	7
All others	4.8	14
Total reserves available for export	35.4	100

SOURCE: Alberta Energy Resources Conservation Board, Alberta Oil and Gas Industry Annual Statistics (Calgary: Alberta Energy Resources Conservation Board, 1979), Report 80-17.

In 1979, TransCanada accounted for more than 50 percent of total reserves available for export, and TransCanada and Alberta and Southern together accounted for 79 percent of the total.

Monopsony, properly defined, denotes the presence of one ('mono') buyer.[18] As such, the current British Columbia natural gas industry structure is a monopsony. In Alberta, where 54 percent of reserves available for export are held by a single buyer (TransCanada), the industry structure leans heavily towards monopsony. At a more micro-level where TransCanada is the sole buyer of natural gas from a number of sellers in a particular field having no other outlets for their gas TransCanada, by definition, is a monopsonist.[19] Until the NEB approves significant increases in exports from Canada or extensions of the Canadian natural gas grid to other gas pipelines (i.e., Q & M-TCPL Pipelines), the quasi-monopsonistic position of TransCanada is not likely to be diluted.

The presence of monopsony can have a definite effect upon field prices. To quote MacAvoy in his book entitled Price Formation in Natural Gas Fields:

> An entirely different set of prices should follow when there is only one purchaser. This "monopsonist" pipeline may have an exclusive supply area for any two-year period so that he can set price in each of several producer's markets. The price most advantageous to him (i.e., that minimizes purchase costs) is lower than the competitive price, and is most likely the same in each field.[20]

The reader is referred to the following chapter (Chapter 2, Sections 2.4 and 2.5) for further discussion of the effects of monopsonistic price formation.

1.5 Government Regulation of the Industry

In the Canadian oil and gas industry, Adam Smith's 'invisible hand' has been increasingly replaced by the 'visible hand', whereby governments are overtly setting prices, controlling gas and oil flows, taxing and providing incentives to the industry and thereby ultimately determining the pattern of resource development.

In Canada, most of the mineral rights are held by governments. In Alberta approximately 80 percent of the mineral rights are held by the province--these are referred to as 'crown' properties. The remainder are 'freehold' properties where mineral rights are held by private interests.

The Alberta government is able to derive substantial revenues from the gas industry in the form of fees, lease rentals, bonus payments, provincial taxes and royalties. Its authority to collect these revenues is derived from provincial ownership rights imparted through a 1930 amendment to the British North America (BNA) Act of 1867. The BNA Act delineates the constitutional powers of the provinces which include the management of natural resources on crown lands within their boundaries and provincial authority to impose direct taxes. This constitutional power plus the rich resource endowment of Alberta, has permitted the provincial government of that province to become actively and profoundly involved in the Canadian oil and gas industry.

The federal government also derives revenues from the natural gas industry chiefly in the form of federal corporate income taxes. Recently (The National Energy Program, 1980) the federal government has introduced three additional taxes (Petroleum Compensation Charge, Natural Gas and Gas Liquids Tax, Petroleum and Gas Revenue Tax) designed to increase federal government revenues from the oil and gas industry. The movement of natural gas through pipelines crossing provincial and international boundaries is also under the jurisdiction of the federal government. The federal government's authority in these areas is imparted through its jurisdiction over interprovincial and international transactions and authority of taxation.

Both levels of government offer the gas industry incentives promoting exploration and development activities.[21] Ideally, incentives are provided with the intention to compensate active firms for the unusual risks associated with this industry. However, where incentives allow more rents to accrue to the operating companies, foreign ownership is an issue as a portion of the rent captured by foreign shareholders, if repatriated, would be lost by Canada.

1.6 Regulatory Bodies Influencing the Canadian Natural Gas Industry

1.6.1 Alberta Energy Resources Conservation Board

Within Alberta the Energy Resources Conservation Board[22] (AERCB or Board), which was established in 1938, performs several functions related to the natural gas industry. One function is to limit the amount of gas flared to quantities

> which experience indicates would not be economical to conserve having regard for the nature of the production and conservation system[23]

The proportion of gas production flared between 1961 and 1971 fell from 43 to 16 percent.[24] This decline is probably a reflection of both the Board's influence and a response to higher natural gas prices.

A second function of the Board pertains to the regulation of out-of-province movements of oil and natural gas.[25] In this regard the Board operates an exportable surplus policy whereby only gas surplus to both contract commitments and forecast future requirements of the province will be approved for export from the province. This function of the Board is more fully discussed in a following section (Section 1.7). The AERCB is also concerned that any approved exportable surplus receives a 'just and reasonable price' and is, therefore, within the public interest.[26]

1.6.2 National Energy Board

Within Canada, the National Energy Board (NEB) performs a role at the national level analogous to that which the AERCB performs for Alberta. The National Energy Board Act of 1959 and subsequent amendments delineated the responsibilities assigned to the NEB. These responsibilities relate to regulation of oil, gas and electric utility industries and to provision of advice to the federal government on the development and use of energy resources. Under its large mandate, it also has the authority to grant applications for export licenses (i.e., from the country). The NEB must satisfy itself that the quantities of energy requested for export do not exceed the surplus remaining after allowance has been made for reasonable foreseeable Canadian requirements. The NEB is also responsible to see that the prices charged for exports are just and reasonable in relation to the public interest and for this purpose has delineated specific price tests.[27]

Thus, the two regulatory boards (the AERCB and the NEB), as well as performing analogous roles at different levels of jurisdiction, define the 'public interest' with due consideration to 'price'.

1.6.3 Federal Power Commission

The Federal Power Commission (FPC) in the United States, while not having direct authorization to control Canadian natural gas prices does exert some influence upon actual prices. Import quotas and regulatory delays in the U.S. on pipeline construction have limited the U.S. market for Canadian gas. In some instances, the FPC has refused approval of the international border price. Currently the Canadian gas industry is voicing concern over slackening gas sales in the United States. Ottawa's decision to raise the export price 30 percent in February of 1980 (to $US 4.47/Mcf) is considered a major factor contributing to this sales drop. Jack MacLeod, President of Shell Canada Limited which is Canada's largest natural gas producer, is quoted as stating that:

> although Canadian producers will not likely push the government to reduce the export price, they may request [and this has been done] that increases be deferred if conditions do not change in the United States.[28]

This would have definite consequences for Alberta producers who receive the differential of the export over the domestic price, net of royalties, taxes and transportation charges.

In response to weakened market conditions in the United States for Canadian natural gas, the Canadian government has backed off somewhat from pricing Canadian gas exports based on the crude oil import substitution value (referred to as the Duncan-Lalonde formula).

On April 1 of this year, however, the natural gas export price was increased to $US 4.94/Mcf, a price below the value which would have been set provided the gas export price remained based on the Duncan-Lalonde formula.

1.7 Development of Regulation as it Affects Natural Gas Pricing

The role of government regulation as it pertains to the natural gas industry has a long history dating back to the discovery of the Leduc field in 1947. The Alberta government's concern with the province's large and growing natural gas inventory after the Leduc discovery precipitated the appointment of a commission under the chairmanship of Robert S. Dinning in 1949. The Dinning Commission, as it became known, was assigned the responsibility of examining the circumstances conducive to Alberta's large natural gas stocks, and estimating future reserve additions and consumption of gas in Alberta. It reported that Alberta requirements for natural gas would be given first priority to supplies, and other Canadian requirements would have prior claims to supplies over non-Canadian requirements.

Following the report of the Dinning Commission, the Alberta Gas Resources Preservation Act was passed in 1949. The intent of this Act was to provide for the possible export of surplus natural gas from Alberta while concurrently protecting the natural gas resources and reserve utilization of these resources for Alberta.

An excerpt from the 1956 Alberta Gas Resources Preservation Act (which superceded the 1949 Act)[29] provides that:

> The Board [AERCB] shall not grant a permit for the removal of any gas or propane from the province unless in its opinion it is in the public interest to do so having regard to:
>
> (a) the present and future needs of persons within the province,
>
> (b) the established reserves and the trends in growth and discovery of reserves of gas or propane in the province.[30]

The AERCB, which was charged with the administration of the Act (under the 1949 version), interpreted a 'surplus' as an amount which known reserves exceeded Alberta's forecast requirements for the next 30 year period. This definition has since been relaxed to encourage continued development of the natural gas industry. In 1956 the surplus formula was changed to account for 'trend' gas,[31] and in 1979 the protection period was shortened to 25 years.[32] This does not exhaust the list of changes to the surplus formula but does provide an indication of the relaxing tenor of the changes adopted.[33]

In 1972, at the request of the Alberta government the Alberta Energy Resources Conservation Board (AERCB, Board) conducted a hearing to review the field pricing of natural gas in Alberta.[34] The Board concluded that it was in the Alberta public interest that the Alberta field price for natural gas be increased to the field value. The term 'field value' to this point in time, however, lacked a precise formal definition in the legislation. The Board recommended that contracts should include a base price consistent with the field value which was estimated to be some $0.26/Mcf to $0.36/Mcf in 1972.[35]

Prior to the the Board's 1972 pricing report, the Alberta public interest as it related to natural gas policy made no mention of price. Thus the Board's 1972 pricing report which made explicit consideration of the natural gas price as it effects the Alberta public interest marked the start of a new course for Alberta natural gas policy.

Another recommendation made by the Board as a result of the 1972 gas pricing hearing was that gas purchase contracts should provide for 'price redetermination' at least every five years, with the price renegotiated on the basis of the field value of gas. The Board also recommended the base price for gas be escalated by 3 to 4 percent annually.

On November 12, 1972, Premier Lougheed presented a statement to the Legislative Assembly entitled 'Alberta Government Statement on New Natural Gas Policies for Albertans'. The essence of this statement indicated the provincial government's general concurrence with the

Board's findings. In this statement the time between price renegotiations was reduced to 'at least every two years' which effectively reduced the significance of the Board's recommendation concerning annual escalation of the base price.

In 1973, the AERCB conducted a second hearing into the field pricing of Alberta natural gas.[36] The Board found that the mid-1973 field value for natural gas in Alberta was somewhere in the range $0.27/Mcf to $0.38/Mcf. In that same year the field value was formally defined in The Arbitration Amendment Act (1973) as:

> . . . the commodity value of gas less just and reasonable costs, charges and deductions that are or may be fixed, determined or allowed for the transportation and distribution of that gas from the point of sale under the gas purchase contract to the point of end use . . .[37]

and where commodity value, in essence, referred to the market value for natural gas based upon the value of competing fuels. Chapter 3, Section 3.5.1 provides for a more rigorous definition and interpetation of the term 'commodity value'. The Board also reported that the average field price for gas for which pricing provisions had been modified had increased since 1972 by $0.08 to $0.09/Mcf which resulted in an average field price for all gas of some $0.20/Mcf.[38]

In 1974, the Board conducted a third review of natural gas field pricing in Alberta.[39] After receiving gas purchase contract information from Alberta gas buyers, the Board reported that the 1974 average field price for gas leaving the province was some $0.46/Mcf. Although this price represented a $0.30/Mcf increase from the 1972 field price, it was considerably below the estimated June 30, 1974 range of its field value (based on commodity value) which was $1.09 Mcf to $1.19/Mcf. However, the Board did not believe that it was reasonable to expect average field prices to have achieved this field value range by June 30, 1974. Thus in order to assess industry response to the Alberta government's natural gas policy adopted in November, 1972, the Board defined a 'target field value' against which average field prices could be measured. The Board estimated this 'target field value' to be $0.50 to $0.60/Mcf by June 30, 1974, and further estimated a second 'target field value' of $0.65 to $0.75/Mcf for contract prices offered at June 30, 1974. Thus, the June 30, 1974 field price of $0.46/Mcf was still below the target field value range for that time.

Precipitated by the Gulf-TCPL arbitration,[40] the federal government in concurrence with the Alberta government in November of 1975 set the Canadian price of natural gas at $1.25/Mcf at the Toronto City Gate. This price was judged to be 85 percent of the Btu equivalence of crude oil. Thus, the price of natural gas was effectively tied to the price of its closest substitute--crude oil. From then to to November 1, 1980 the price of natural gas has been redetermined with each escalation in the domestic crude oil price in an attempt to maintain approximately 85 percent Btu equivalence position with crude oil at the Toronto City Gate.[41] Starting November 1, 1980, however, it is the stated intention of the federal government (i.e., The National Energy Program, 1980) to let gas prices rise less quickly than oil prices in order to encourage a shift away from oil to natural gas. This pricing policy may be simply viewed as a relaxed version of the '85 percent rule' used previously (e.g., '67 percent rule').[42]

The net back to Alberta producers ensuing from this '85 percent rule' legislation (and its relaxed version) is calculated by subtracting the distribution and transmission charges from Toronto to the field.[43]

The Natural Gas Pricing Agreement Act was made effective in 1975 in order to resolve the likelihood of a potential conflict between the following two pricing regimes:

1. 'commodity value' applicable to natural gas arbitrations
2. '85 percent rule' legislation imposed by federal and provincial concurrence, in November 1975

The intent of this Act was to override any other price redetermination such as those awards made under The Arbitration Amendment Act (1973). To quote from the Natural Gas Pricing Agreement Act:

> Where a federal-provincial agreement is in effect during any month, the price of gas delivered in Alberta in that month under a gas sales contract for consumption within Alberta shall be
>
> (a) an amount equal to
>
> (i) the Alberta border price for the month plus the price adjustment for the month
>
> less
>
> (ii) an amount estimated by the designated officer as the amount that would be the Alberta cost of service with respect to the gas and the movement of the gas from the contract delivery point to a point on the Alberta border specified by the designated officer if the gas were to be moved between those points and pipeline facilities were available for that purpose,
>
> or
>
> (b) an amount equal to the contract field price plus the price adjustment for the month whichever is the lesser.[44]

The essence of this legislation was to restrict the field price of natural gas destined to Alberta markets for consumption to be the lesser of the contract price or the net back ensuing from out-of-province base point markets--even when the former reflects the commodity value within Alberta.

Also, in November 1975 the natural gas export price was set at $1.60/Mcf at the Canada-U.S. border. Since that date, the Canadian export price has been increased, predicated on the 'substitution value' of crude oil imported into eastern Canada.[45] The reason for basing the gas export price on the crude oil import price rather than the domestic price for crude stems from the fact that the current domestic oil price is heavily subsidized. An export price for gas based on the price of a subsidized substitute would be equivalent to the direct subsidization of U.S. gas consumers by Canadians. Since 1977, the Canadian export price has been set in U.S. dollars acknowledging the recent decline in the exchange value of the Canadian dollar. The difference between the export and domestic gas prices, net of royalties, taxes and transportation charges, is returned to Alberta gas producers on a pro rata basis regardless of whether a particular producer's gas is destined to the export market.

The gas pricing situation in British Columbia as was alluded to earlier (Section 1.4) differs from that in the rest of Canada. In B.C., the British Columbia Petroleum Corporation (BCPC), which is a publicly owned company, acts as a monopsonist in the gas market, buying gas from the B.C. producers and selling the gas to Westcoast Transmission. The price that Westcoast pays to the BCPC for the gas it receives is supposed to reflect the commodity value of the gas less transportation charges. In essence, the BCPC is acting as the rent collector for the province, expropriating the difference between the market and purchase prices of the gas.

Footnotes

[1] Westcoast Transmission. "Submission to the Borden Commission Hearing - Price of Gas in the Field Related to Trend of Gas Discovery" (Calgary: Westcoast Transmission, 1957), p. 64.

[2] Exploration activity is non-directional in the sense that this activity cannot be precisely directed towards the search for oil or gas. However, there are gas-prone and oil-prone areas where exploration activity is more likely to produce either gas or oil finds.

[3] The life index is defined as the ratio of remaining reserves to annual production.

[4] See G. C. Watkins, "Canadian Oil and Gas Pricing", Oil in the Seventies (Vancouver: The Fraser Institute, 1977), p. 100.

[5] G. C. Watkins, Regulation of the Export of Gas from Alberta, mimeo, 1973.

[6] Ibid.

[7] The significance of Figure 1.1 is that it was often used to represent the long term trend in Canada's gas discoveries by the National Energy Board. For Alberta gross additions to reserves are approximately 2.5 Tcf per year.

[8] Exploratory and development (excluding oil development) drilling footage for Alberta was 7.0 mmf in 1968, 7.9 mmf in 1972, 10.2 mmf in 1973 and 14.7 mmf in 1977. See Canadian Petroleum Association, Statistical Handbook, 1979.

[9] Within Alberta, The Alberta Gas Trunk Line as a common carrier is subject to regulation by the Public Utilities Board of Alberta.

[10] National Energy Board, Reasons for Decision in the Matter of the Applications Under Part III of the National Energy Board Act of TransCanada Limited and Q & M Pipe Lines Ltd., April 1980.

[11] Independent Petroleum Association of Canada. "Submission to the Energy Resources Conservation Board Proceeding No. 6157, Field Pricing of Natural Gas" (Calgary: Independent Petroleum Association of Canada, 1972).

[12] Refer to Canadian Petroleum Association, Statistical Handbook (Calgary: Canadian Petroleum Association, 1979), Section VI, Table I. Nominal prices for Western Canada deflated by Gross National Expenditure (GNE) implicit price index.

[13] Independent Petroleum Association of Canada. "Submission to the Energy Resources Conservation Board Proceeding No. 6157, Field Pricing of Natural Gas" (Calgary: Independent Petroleum Association of Canada, 1972), p. 5.

[14] See James W. McKie, "The United States", *The Oil Crisis* (New York: W. W. Norton & Company, Inc., 1976), pp. 74-75.

[15] Thomas Kennedy, *Globe & Mail*, Toronto, December 12, 1972.

[16] Independent Petroleum Association. "Submission to the Energy Resources Conservation Board Proceeding 6157, Field Pricing of Gas in Alberta" (Calgary: Canadian Petroleum Association, 1972). Although the Association did not directly refer to TransCanada as a monopsonist this was implicit throughout their submission.

[17] Canadian natural gas producers, as well as being numerous, are all relatively small with the largest single producer producing 9 percent of total production in 1971. The top 5 producers accounted for 35 percent of total production, the top 10, 61 percent; the top 20, 77 percent; and the top 35, approximately 85 percent. See Stanford Research Institute. *The Market Price for Natural Gas from Sources in Western Canada, 1972-1990, Volume I: Main Report (Menlo Park: Stanford Research Institute, 1972)*.

[18] The reader is referred to the following chapter which is a theoretical discussion of monopsony and the effects of its presence.

[19] This, of course, would hold for other buyers as well where they are the only pipelines.

[20] Paul W. MacAvoy, *Price Formation in Natural Gas Fields, A Study of Competition, Monopsony and Regulation* (New Haven: Yale University Press, 1962), p. 75.

[21] W. B. Friedenberg, Z. C. Slagorsky, A. J. Walsh*
"Government Incentives in Canada's Petroleum Industry" (Calgary: Canadian Energy Research Institute, 1980), Working Paper 80-1.
*nee: A. J. Nixon

[22] This board was initially established as the Petroleum and Natural Gas Conservation Board in 1938 and was later renamed the Oil and Gas Conservation Board. Its present title was given in 1971 when its powers were extended to include functions related to other energy resources (i.e., coal, hydro and thermal electric) besides oil and gas. See the Province of Alberta, *Energy Resources Conservation Act*, S.A. 1971, Chapter 30.

[23] Alberta Energy Resources Conservation Board, *Conservation in Alberta, 1971* (Calgary: Alberta Energy Resources Conservation Board, 1972), p. 13.

[24] Ibid.

[25] This function of the Board is granted under the Alberta Gas Resources Preservation Act, 1956.

[26] Alberta Energy Resources Conservation Board. "Report on Field Pricing of Gas in Alberta" (Calgary: Alberta Energy Resources Conservation Board, 1972), Report 72-E-OG, p. 6-1.

[27] Canada, National Energy Board Act, 1959, Section 83.

[28] The Globe and Mail, May 27, 1980, p. 89.

[29] The 1949 Act was replaced by the Alberta Gas Resources Preservation Act, 1956. The intent, purpose and objectives of this latter Act are, in essence, the same as the 1949 Act.

[30] See the Statute of Alberta, Alberta Gas Resources Preservation Act, Chapter 157, Paragraph 7 (3), 1956.

[31] Trend gas refers to anticipated reserve additions.

[32] Alberta Energy Resources Conservation Board, "Alberta's Gas Supply Protection, Procedures and Formula" (Calgary: Alberta Energy Resources Conservation Board, December 1979), Report 79-I.

[33] A further indication of the tenor of the changes to the surplus formula is provided by the 1969 amendment to The Gas Resources Preservation Act, 1956 contained in AERCB Report 69-D. In this report the decision was made to consider a portion of the deferred gas reserves as part of the contractable reserve base in the surplus calculation. Prior to 1969, deferred gas reserves had been excluded from the contractable reserve base.

[34] Alberta Energy Resources Conservation Board, "Report on Field Pricing of Gas in Alberta" (Calgary: Alberta Energy Resources Conservation Board, August 1972), Report 72-E-OG.

[35] The range reflecting variations in market conditions as well as variations in the geographical location of the producing field. The Board's appraisal of the 1972 field value was based upon the estimated commodity value of Alberta gas in its two main extra-provincial markets and the costs of supplying Alberta gas to these markets.

[36] Alberta Energy Resources Conservation Board, "Review of Field Pricing of Gas in Alberta" (Calgary: Alberta Energy Resources Conservation Board, August 1973), Report 73-I-09.

[37] Province of Alberta, The Arbitration Amendment Act, R.S.A. 1973, Chapter 88.

[38] The Board attributed this higher range to inflation and lack of interfuel competition.

[39] Alberta Energy Resources Conservation Board, "Review of Field Pricing of Gas in Alberta" (Calgary: Alberta Energy Resources Conservation Board, August 1974), Report 74-P.

[40] A major arbitration between Gulf Oil Canada and TransCanada Pipelines in the Spring of 1975 demonstrated the considerable pressure on gas prices brought about by the continued increases in oil prices at that time.

[41] As of July 1980 the Toronto City Gate price was some 82.5 percent of the Btu equivalent crude oil price where the crude oil price excludes the $1.00 per barrel Syncrude levy.

[42] It is the stated objective of the federal government to have the gas price determined as 67 per cent of the Btu crude oil price by 1983. This is to be achieved gradually over the next three years by slowing down the rate of increase of gas prices relative to oil prices. See Department of Energy, Mines and Resources, Canada, The National Energy Program, 1980, (Ottawa: Energy, Mines and Resources, 1980), p. 32.

[43] Refer to Chapter 3 to a section entitled 'Net Back Pricing' for a more detailed discussion of this 'net back' procedure.

[44] Province of Alberta, The Natural Gas Pricing Agreement Act, S.A. 1975, Chapter 38.

[45] In response to weak market conditions in the United States for Canadian natural gas, the federal government has recently backed off somewhat from pricing Canadian gas exports based on the crude oil import substitution value. However, it is still the federal government policy to price natural gas exports based on crude oil import costs.

CHAPTER 2

PRICE THEORY IN THE CONTEXT OF THE NATURAL GAS INDUSTRY

2.1 Introduction

The purpose of this chapter is to outline those aspects of price theory which may be relevant to the issue of natural gas pricing. In particular, the chapter focuses upon the role of price within the market as a rationing mechanism and the implications for resource exploitation. Also outlined are those characteristics peculiar to the natural gas industry which have an effect upon the determination of natural gas prices. The chapter concludes with a discussion of the implications of a dual-price system for natural gas under different optimizing strategies, i.e., maximizing profits versus maximizing national welfare.

2.2 The Role of Price

In a free enterprise economy,[1] there is no conscious concern on the part of any individuals or organizations for the familiar triad of economic problems: WHAT, HOW and FOR WHOM are goods to be produced.

> Every individual . . . intends only his own security, only his own gain. And he is in this led by an invisible hand to promote an end which was no part of his intention. By pursuing his own interests he frequently promotes that of society more effectively then when he really intends to promote it.[2]

As such, a system of markets and prices provides an unconscious coordinating and organizing force. Prices provide signals in the market place allocating resources to those uses where they are most highly valued. In this way the price mechanism acts as a rationing device bringing the quantity demanded and supplied into balance. In short, provided that markets are sufficiently developed and competitive, prices will induce both consumers and producers to temper their behavior as market conditions change.[3]

However, the competitive conditions assumed above may not hold: government regulation may be imposed or 'natural' monopoly may preclude competition. The following section is concerned with the institutional characteristics of the natural gas industry which have an effect upon the determination of natural gas prices.

2.3 Background for Analysis

The gaseous state and high volatility of natural gas itself make transportation and storage of this commodity more difficult and costly than for oil or oil products. In general, transportation of natural gas is by pipeline.[4] The construction of pipelines (and the associated apparatus, i.e., compressor stations and straddle plants) is highly capital intensive and requires long lead times.[5] The capital intensity of such projects is reflected in the practice of 'prepayment' to pipeline companies by their agents. 'Prepayments' are like interest free loans and are usually paid back over the early years that the pipeline is in operation. Although prepayments did not become prevalent until the late 1960s long after the major lines were built, Canadian pipelines (e.g., TransCanada) found themselves in a position of having to offer prepayments to producers in order to remain competitive with the U.S. pipelines entering the Canadian market and offering such prepayment schemes. The reader is referred to an earlier discussion (Chapter 1, Section 1.3.3) of this issue. Traditionally, natural gas sales are on long term contracts (e.g., 20 years), another indication of the nature of the commitment necessary to guarantee the financing of major projects.

Before construction of a pipeline commences, sufficient reserves of natural gas must be committed to ensure economic viability of the line. On a Btu (British thermal unit) basis, natural gas is more expensive than crude oil to move by pipeline,[6] making economic viability of the line more difficult to secure.

Pipeline transportation is an activity characterized by economies of scale (declining unit costs). Where the long run average cost function declines continuously, the firm is considered to be a 'natural monopoly'. A study by Leslie Cookenboo, Jr.[7] concluded that unit transportation costs are minimized when pipelines operate to carry shipments conglomerately in as large quantities as is possible in large diameter line. This study also concluded that unit costs would continue to decline indefinitely if larger pipe could be obtained without having to pay a premium price.

Where there are large economies of scale there is limited possibility of effective competition among many independent firms. Furthermore, where economies of scale persist over the complete range of output, perfect competition is neither feasible nor efficient. A single firm may expand displacing other small competitors to take advantage of such economies of scale, resulting in large concentrations of gas reserves being committed to a single buyer, and at the same time lowering price and average cost. Where large economies of scale are conducive to the development of monopoly,[8] operation by a single firm confèrs efficiency benefits since scale economies allow it to produce at lower real resource costs to society.

Pipeline companies often provide essential services. However, since they are operated as private enterprises conducted for profit, pipeline companies could exploit their powers to the public detriment. Thus the familiar 'natural monopoly' argument is used to exonerate utility regulation. Paul Samuelson writes:

> Under persisting decreasing costs for the firm, one or a few of them will so expand their q's [quantities] as to become a significant part of the market for the industry's total Q. We would then end up (1) with a single monopolist who dominates the industry; (2) with a few large sellers who together dominate the industry . . . or (3) with some kind of imperfection of competition that, in either a stable way or in connection with a series of intermittent price wars, represents an important departure from the economist's model of "perfect" competition wherein no firm has any control over industry.[9]

Milton Friedman, while stating his preference for private monopoly over public monopoly or public regulation, writes:

> However, monopoly may also arise because it is technically efficient to have a single producer or enterprise . . . When technical conditions make a monopoly the natural outcome of competitive market forces, there are only three alternatives that seem available: private monopoly, public monopoly, or public regulation.[10]

Regulation is imposed to ensure that the monopolist acts in the best interests of society. 'Best interests' in the natural gas industry are usually expressed by rate of return regulation.

Due to the long term nature of the commitment involved in the construction and operation of a pipeline, natural gas contracts have been designed to provide some security and at the same time flexibility to both the pipeline company and producer. Flexibility in the field price of gas is provided by:

- periodic escalations, intended to calibrate with declining tariffs, to provide for increases in the cost of gas production and to recognize the purchaser's (i.e., pipeline) ability to pay higher prices as the pipeline capacity utilization increases;
- specific adjustments to provide for factors such as heating or currency values;
- favoured nation provisions, to ensure more favourable terms offered to other sellers (producers) subsequent to the signing of a contract are also extended by the purchaser (pipeline); and
- redetermination of the base price, which provides the seller the opportunity to earn a higher price if the market value of the gas should increase with time.

Security of gas supply is acquired through:

- prepayment schemes, lump sum payments made to the producer at the time the contract is executed and repaid without interest to the pipeline during the early years of gas delivery;
- agreement on rates of take, which specify the average rate at which the seller agrees to deliver and the buyer agrees to purchase gas;

- take-or-pay provisions, which require the buyer to purchase some minimum annual quantity of gas whether or not he takes delivery of this quantity; and
- the long term nature of the natural gas contracts themselves, which generally extend about 20 years.[11]

In short, the nature of the natural gas industry dictates a corresponding pricing arrangement.

To ensure economic viability of gas pipelines in the long run, large fixed costs must be met. In order to meet these costs capacity utilization of the line must be kept high. Consequently, to secure the required degree of capacity utilization, initial prices accepted by producers are generally lower than the averge price in the long term. Initial prices below the long run value of the gas are accepted on the prospective view that higher values will be received some time in the future.

Under conventional pipeline tariff-setting procedures[12] the real (constant dollar) tariff declines over time. This time pattern of tariffs results in producers' achieving increased value for their gas. As tariffs decline, field prices may increase without affecting the price in the consuming market. The use of conventional pipeline tariff-setting principles, however, has come under criticism as it discriminates between early and later users of a pipeline.

If the pipeline company acts as a common carrier[13] of the gas it delivers, and provided there are several producers selling gas and several distributors buying it, then price formation may be achieved in a fairly competitive manner. As a common carrier, however, it is assumed that the pipeline charges approximate competitive levels since common carrier provisions provide for rate of return regulation. On the other hand, if the pipeline company buys and sells the gas it carries, competitive price formation may be prevented from materializing. Under such circumstances, regulation has been used as a surrogate for competition and to achieve price levels which would approximate those received under competition.

Unlike oil pipeline companies which are common carriers, gas pipeline companies, with a few exceptions,[14] own the gas that is transported. In the field, numerous gas producers face a sole buyer and have no other outlets for their gas. This lack of competition between natural gas purchasers (i.e., pipeline companies) has definite consequences for the pricing of natural gas. It characterizes the Canadian natural gas industry as potentially monopsonistic,[15] a situation in which buyers are conferred with monopoly powers.

2.4 Monopsonistic Exploitation of a Resource

The nature of monopsonistic exploitation can be best understood by comparing monopsony with the economist's model of perfect competition. As a 'model' the 'perfectly competitive model' embodies several assumptions. One such assumption concerns the number of buyers and sellers in the market place. They are to be so numerous that their individual actions will not affect the price at which goods are sold. Perfect competition, in equilibrium,[16] leads to the use of resources that is, given certain optimizing criteria, 'best'. Perfect competition results in the maximization of economic efficiency, and provided that private and social costs do not diverge, it will also maximize economic welfare.[17]

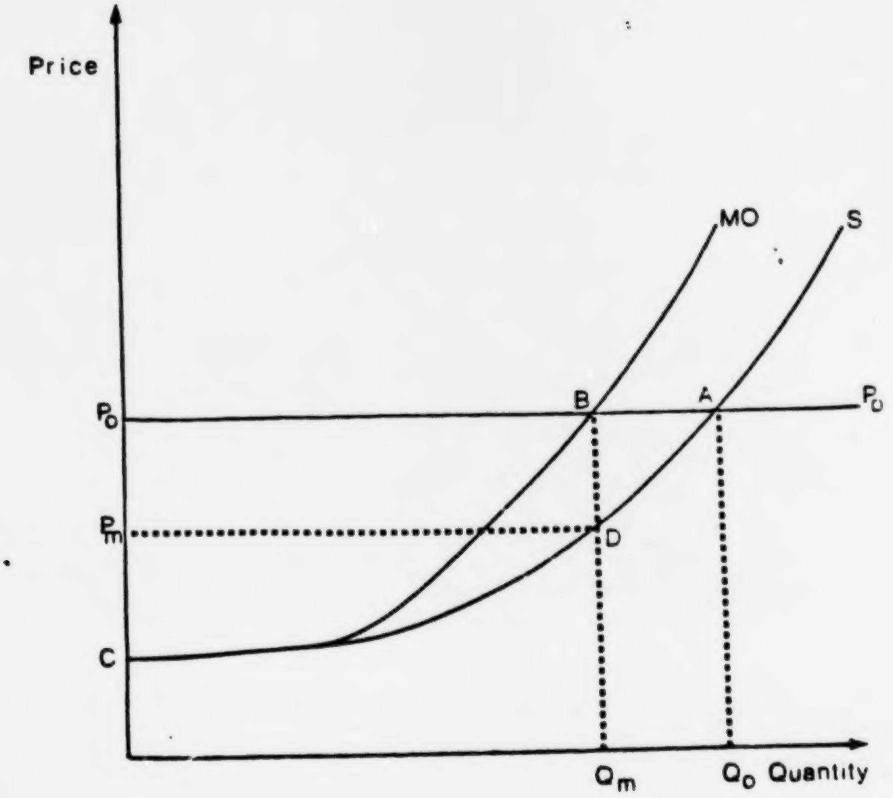
However, the perfectly competitive model is just that: an abstraction from reality. In the real world, you would be hard pressed to find a market which met all of the conditions of the perfectly competitive model. Nevertheless, it serves as a useful analytical tool in the evaluation of the departure of reality from the hypothetical ideal. Monopsonistic pricing is one such deviation.

In the perfectly competitive situation each firm is so small it is unable to exert any influence upon the prices of inputs or outputs. It accepts the prices of these as given. In contrast, the profit maximizing monopsonist does exert influence over the price of inputs. A monopsonist cannot purchase an unlimited quantity of an input at a uniform price. The price the monopsonist must pay for each incremental unit of input is given by the market supply curve for the input, which is generally assumed to be upward sloping. Thus, incremental inputs are only available to the monopsonist at higher prices, but this higher price is also assumed to apply to all previously supplied inputs (assuming he is not a perfectly discriminating monopsonist). In this regard the reader is referred to Chapter 1, Section 1.3.3 and Section 1.4, which discusses the development of Canadian natural gas pricing and the monopsonistic position of TransCanada as a purchaser of Canadian natural gas.

Figure 2.1 provides an illustration of the general effects of monopsony in comparison with the price and quantity established under perfect competition. The horizontal line labelled P_0P_0 is assumed to represent the 'maximum offer price' of the pipeline purchasing natural gas reserves. The 'maximum offer price' is defined as the difference between the price at the point of resale and the average cost of transporting the gas from the field to the resale market (which includes the transporter's rate of return).[18] For simplicity, the offer price is shown as a constant.[19] The maximum offer price is assumed to be determined exogenously.

In Figure 2.1, the curve labelled S is the natural gas industry supply curve which slopes upwards to denote the additional resource units becoming available as the resource price increases. Higher prices are necessary to induce the production of increased supplies from existing reservoirs, as they approach capacity, and from new, but poorer prospects.[20]

Given competition, the quantity marketed would be determined by the intersection of the maximum offer curve (P_0P_0) and the industry supply curve (S). At this intersection (denoted A) the maximum offer price is exactly equal to the minimum price required by producers to induce supply of Q_0 units of natural gas. Q_0 units of gas are supplied at price P_0. All of the natural gas units supplied at price P_0, except for the marginal unit, are assumed to provide producers with surplus benefits. These units are all purchased by the pipeline company at the uniform price P_0, which is in excess of the minimum


Price
MO
S
B
A
P_o
P_o
P_m
D
C
Q_m
Q_o Quantity

SOURCE: G. C. Watkins, "Natural Gas Price Formation," mimeo, 1972.

Figure 2.1: Monopsony Price Formation

payments required to induce supply Q_o. This 'producer surplus' is represented by the area P_oAC in Figure 2.1

Whenever possible, it is to the transporter's advantage to pay something less than the maximum offer price for the gas supplies it receives since the difference between the maximum offer price and the supply price represents incremental profits. In the case where there is a single buyer (monopsonist) the cost for him to increase his purchases stems from the higher cost of incremental supply and also the associated higher price which must be paid for all existing supply. Stated more succinctly, the marginal outlay of the monopsonist is the increase in total cost attributable to the addition of a marginal unit of the variable input. This, of course, assumes that all units are purchased at a uniform price. Thus, the supply curve underestimates the marginal outlay of the monopsonist. The marginal outlay curve (MO)[21] which lies above and to the left of the supply curve (S) denotes the marginal expense to the pipeline of purchasing natural gas and is depicted in Figure 2.1.[22] It would not pay the monopsonist to employ the resource beyond the level of supply Q_m, where the marginal outlay--the addition to total cost--begins to exceed the incremental revenues--the addition to the monopsonist's total revenue from an additional input unit. Thus, Q_m is the profit maximizing level of purchase for the monopsonist. The monopsonist need only pay P_m to secure Q_m units of resources; the difference between P_m and P_o representing potential excess profits (i.e., rent) to the monopsonist[23] and area P_mP_oBD representing total excess profits on Q_m units of resources. Although regulation of resale prices could erode some of this excess profit (by effectively lowering the P_oP_o line) it would never be able to totally erode excess profits as long as the marginal outlay curve (MO) lies to the left of the supply curve. The enforcement of pipeline rate of return regulation without time lags may also offset any accrual of excess profits to the pipeline. It is doubtful, however, that such regulation would restore competitive prices to the producer; rather it would pass on monopsony prices to the distributor.

Thus the presence of monopsony results in the determination of a price (P_m) to the producer which is below the competitive price level (P_0) and the quantity of the resource employed is restricted below competitive levels. As such, there is a social loss attributable to monopsony. The area ABD in Figure 2.1 represents this loss to society. Employment of the resource is restricted to the level Q_m where the resources' contribution to the firm and value to society (set by P_0) is greater than the cost of incremental output. Viewed alternatively, this social loss is an erosion of 'producer surplus' which would be forthcoming with additional production to the level Q_0.

The preceding analysis has compared the theoretical model of perfect competition with one important departure from this model--monopsony (buyer's monopoly). The main conclusion to be drawn from this analysis is that the presence of monopsony will result in the determination of prices and quantities below competitive levels. The following section is directed towards an analysis of the effects of monopsonistic price formation.

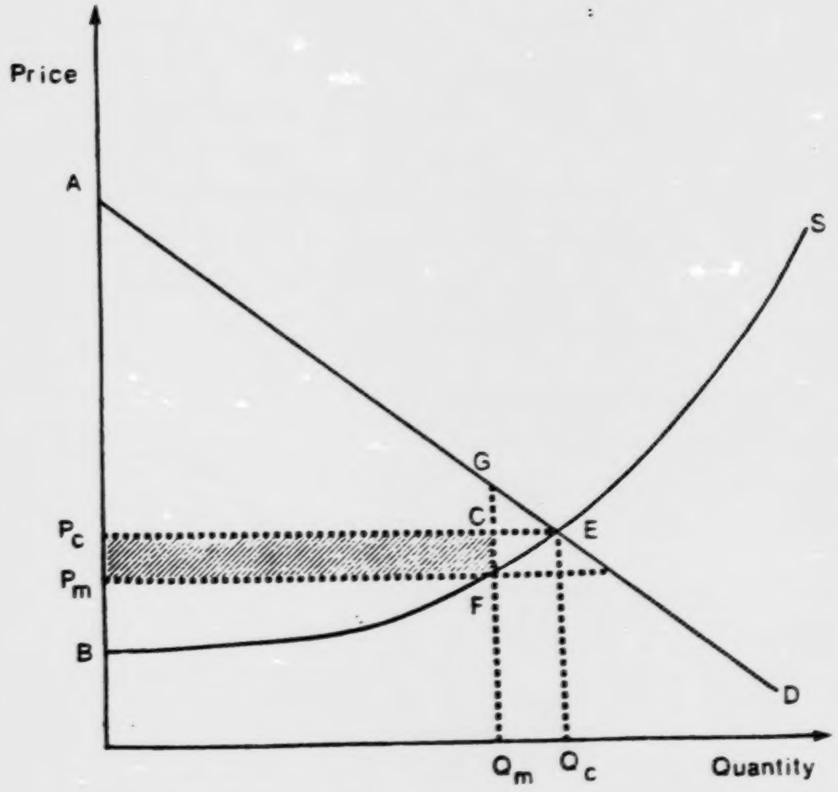
2.5 Effects of Monopsonistic Price Formation

Monopsonistic conditions give rise to prices and quantities to the producer which are below what would otherwise prevail had competition prevailed. In Alberta, a series of Board (AERCB) hearings were held between 1972 and 1974 (refer to Chapter 1, Section 1.7) in which it was concluded that Alberta natural gas field prices were restricted below their field values, a price which was to reflect competitive conditions. This concern eventually prompted provincial legislation to determine gas prices (based on commodity value) under arbitration. Further concern over gas prices in 1975 prompted federal legislation and the well publicized '85 percent rule' for determining gas prices was born. The reader is referred to Chapter 1, Section 1.7, for a more detailed discussion of the events culminating in these pieces of legislation. The reader is further referred to the following chapter (Chapter 3, Sections 3.4 and 3.5) which is an analyses of these two legislated pricing mechanisms (i.e., commodity value and 85 percent rule pricing).

The following analysis is carried out with reference to Figure 2.2. Under competitive conditions for the purchase of gas from producers the equilibrium price and quantity (P_c, Q_c) would be determined by the intersection of the demand (D) and supply (S) functions. This competitive equilibrium maximizes the sum of consumer and producer surpluses. Consumer surplus, as it is used in this context, represents the difference between the amount the consumer (i.e., transmission company) would be willing to pay less the amount he has to pay at a uniform price. Referring to Figure 2.2, the consumer surplus is represented by the area denoted AP_cE and the producer surplus[24] is denoted P_cBE, when the competitive price prevails. Figure 2.2 is analogous to Figure 2.1 except for the substitution of a downward sloping demand curve for the P_oP_o curve and the absence of a marginal outlay (MO) curve.

Under monopsonistic conditions, price and quantity are established below their competitive levels. With reference to Figure 2.2, the monopsony price paid to producers is shown as P_m. The manner in which this price is established was shown earlier (Figure 2.1).

Moving from a situation of competitive to monopsonistic price determination, producers suffer a loss in their surplus represented by the area P_cEFP_m. This loss is partially offset by a gain in consumer surplus which is represented by the area P_cCFP_m (shaded area in Figure 2.2). The consumers gain by having access to gas at reduced prices. Their gain, however, does not totally offset producers' losses since gas production is cut back at this lower price. The net result is a loss represented by the triangular area CEF, which is a 'deadweight' loss by producers. A 'deadweight' loss signifies a loss which is not recouped by a gain to another party. Although consumers gain by having access to gas at a low monopsonistic price they lose the consumer surplus, denoted GEC, that would have accrued on units of production not purchased (i.e., consumer surplus on Q_mQ_c units of production). Note that to purchase these units (Q_mQ_c) they would have had to offer the competitive price (P_c). Consequently, area GEC also represents a 'deadweight' loss--this time suffered by consumers.


Price
A
S
G
C
E
P_c
P_m
F
B
D
Q_m
Q_c
Quantity

SOURCE: G. C. Watkins, "Natural Gas Price Formation," mimeo, 1972.

Figure 2.2: The Effects of Monopsonistic Price Formation

To summarize, monopsonistic price formation results in a deadweight loss to society represented by the area GEF in Figure 2.2. Total welfare to society is maximized at the competitive solution (P_c, Q_c), which maximizes the difference between the total value society places upon the natural gas (i.e., area under the demand curve) and the real resource costs associated with producing natural gas (i.e., area under the supply curve). The monopsonist, however, restricts supply (Q_m) below the competitive level and thus imposes a loss in total societal welfare. That is, at Q_m the marginal value society places on these resources exceeds their marginal resource cost implying that output should be expanded. As a qualifying note it should be mentioned that the preceding analysis is static in the sense that the temporal process of adjustment of the variables has been disregarded.

Lower field prices for natural gas may be passed on to gas distributors and finally consumers or they may be enjoyed by the transmission companies in the form of additional profits. Regulation of transmission companies' rates of return, such as the National Energy Board's regulation of TransCanada Pipelines Limited (TCPL), makes the accrual of excess profits by these companies difficult to maintain over the long term.

In terms of judging whether a change is socially desirable, a number of compensation criteria have been formulated by such economists as Kaldor, Hicks and Scitovsky. These criteria extend beyond the Pareto welfare criterion which imposes an automatic veto on any policy involving a loss to any party.[25] For example, if the winners can profitably bribe the losers into accepting the change, then the Kaldor compensation criterion would deem one position preferable to another. Employing the Hicks compensation criterion would require that the losers be unable to profitably bribe the potential winners into forfeiting the change. The Scitovsky criterion, which adjoins the Kaldor and Hicks criteria, requires that the winners be able to profitably

bribe the losers into accepting the change, and at the same time the
losers be unable to profitably bribe the potential winners into for-
feiting the change. Under each compensation criterion discussed above
it is the 'ability to pay' which becomes the decision factor, whether
income is actually redistributed or not is another question.

Employing these criteria with respect to Figure 2.2, it is
the producers which suffer a net loss and the transmission company
which enjoys a net gain associated with a move to monopsony level
prices (i.e., predicated pipeline rate of return regulation). Since
the gain to the transmission company does not wholly offset the loss to
producers, the Kaldor compensation criterion would judge the move as
undesirable. The Hicks compensation criterion would agree; the net
losers (i.e., producers) would be further ahead, by the area CEF,
offering area P_cCFP_m as a bribe to the transmission company in
order to remain receiving competitive prices for their gas. Since both
the Kaldor and Hicks criteria would determine the competitive solution
as the preferred position it is tautological that the Scitovsky crite-
rion would concur.

Another welfare criterion which has been employed rests not on
the 'ability to pay' decision factor but on a value judgement about the
'means' by which an outcome is generated. The resulting income distri-
bution may meet this criterion provided that the means by which this
income distribution was generated is deemed acceptable. In this case,
value judgements are made on activities rather than on the income
distribution generated by these activities. For example, any income
distribution arising from the operation of a free market may meet this
welfare criterion provided the operation of the 'free market' is judged
to be an acceptable activity. Again refering to Figure 2.2, the com-
petitive solution may be selected as the preferred situation provided
competitive activities are judged acceptable vis-a-vis non-competitive
(i.e., monopsonistic) activities.

The foreign ownership issue is another area where these various
compensation criteria may be employed. For example, consider the
situation where a 100 percent foreign owned petroleum industry

restricts supply and raises prices (e.g., monopoly). Utilizing the Kaldor compensation principle, if the gainers (i.e., foreign owned industry) could profitably bribe the losers (i.e., Canadian consumers) into accepting these monopoly conditions, then this would be the preferred outcome. Here is where the 'ability to pay' decision factor may no longer suffice, as it is Canadian welfare which we are attempting to maximize. In resolving this issue it is important that 'actual' compensation be paid since in this example, Canadians are the losers and the gainers are non-Canadians. Payment by foreign producers to Canadian consumers for losses incurred would be Pareto optimum in so far as 'Canadians' were concerned. This compensation may be collected for Canadians through the Canadian taxation system. This foreign ownership issue is dealt with further in a following section (Section 2.6.1), specifically as it relates to trade policy.

As well as the direct and more immediate affect of moving from a situation of competition to monopsony, (i.e., deadweight losses in producer and consumer surpluses) there are other effects of such a move which are of a more long term nature. In the petroleum industry, oil and gas supplies are made available through long term exploration and development activities. The level of exploration and development activities today, which are directly influenced by prices (i.e., net revenues) today and future expectations about prices, will determine the level of future supply. A lower than competitive price would detract from interest in exploration and development activities having a bearing upon the long run supply curve of the gas industry.[26] The long run supply curve is shifted to the left by depletion and to the right by discoveries and new technologies; the net effect of the two opposing forces determining the overall shift in the long run supply curve. If the discovery rate recedes because of lower prices (i.e., resulting from monopsony) this may cause an overall leftward shift in the long run supply curve as depletion occurs. A leftward shift in the supply curve does not necessarily mean an absolute resource loss (i.e., irrevocable resource loss).[27] Rather, resources will await discovery and development until such time as they become economic.

By way of a summary, in the short run prices maintained below competitive levels will exclude some gas consumers from enjoying the benefits of consumption because the lower price does not elicit sufficient supplies to satisfy incremental demand, while at the higher competitive price there would be sufficient gas to meet all demands at that price. In the long run, a relatively greater number of potential natural gas buyers are excluded from enjoying the benfits of consumption as the gas supply contracts over time in response to a slowdown in reserve additions initiated by too low a price.

2.6 Price Discrimination

Canada currently maintains a dual-price system for its natural gas sales, charging higher prices in export than domestic markets (the reader is referred to Chapter 1, Section 1.7, which discusses the development of this two price system for Canadian natural gas). The maintenance of a two price system characterizes Canada as a 'price discriminator'.[28]

At the outset it should be mentioned that the following analysis is a partial equilibrium analysis in that it considers the natural gas industry in isolation from the rest of the economy, as opposed to a general equilibrium analysis whereby the entire economy is considered as an interactive unit. As such, the intricate feedback mechanisms which operate to link the various sectors of the economy have been excluded from the analysis.

The maintenance of a dual-price system for Canadian natural gas is possible because of the barriers (i.e., imposed export quotas) effectively preventing the free movement of gas between Canada and the United States.[29] In this regard, the reader is referred to an earlier discussion (Chapter 1, Section 1.6.2) of the export permits awarded by the National Energy Board. If such barriers were not present, competition would induce a basing point pricing scheme whereby output was expanded to the level at which the marginal cost of supply equalled the producer return[30] at the 'market interface'. The market interface is that market in which the delivered price of natural gas from one source is equalized with the delivered price from an alternative source. In the following chapter (Chapter 3, Section 3.3) a system of competitive pricing (i.e., basing point pricing scheme) is more fully discussed.

2.6.1 A Policy of Free Trade

A point of departure for this analysis of price discrimination is provided by a discussion of free trade and its implications upon prices and quantities. This analysis is based upon work by P. G. Bradley.[31] The following discussion refers to Figure 2.3 which is a two panelled illustration showing the U.S. demand-supply situation for natural gas in the upper panel and the Canadian situation in the lower panel. The upper panel shows the U.S. demand (D_{us}) and supply (S_{us}) curves for natural gas intersecting at $\overline{P}_1$ which is above the prevailing price P_R. Price P_R represents the ceiling price set by the Federal Power Commission in the U.S. This graph illustrates the current U.S. natural gas shortage which has resulted from an imposed price ceiling on natural gas which is below the equilibrium level--the level balancing demand and supply ($\overline{P}_1$). Also shown in the U.S. panel of Figure 2.3 is an excess demand curve labelled E_{us}. This curve represents the amount by which U.S. demand exceeds U.S. supply, at price levels below the equilibrium price ($\overline{P}_1$). At the equilibrium price ($\overline{P}_1$), there is zero excess demand whereas at any price less than this equilibrium price, such as P_R, excess demand is some positive amount.

The lower panel of Figure 2.3 illustrates the demand-supply situation in the Canadian natural gas market. The equilibrium price and quantity ($\overline{P}_2$, $\overline{Q}_2$) denote the balancing of Canadian demand and supply in a closed market. Under a policy of free trade, however, any excess demand emanating from the U.S. market would be transmitted to the Canadian gas market, exerting competitive pressure. The transmission of U.S. excess demand to the Canadian market is illustrated by

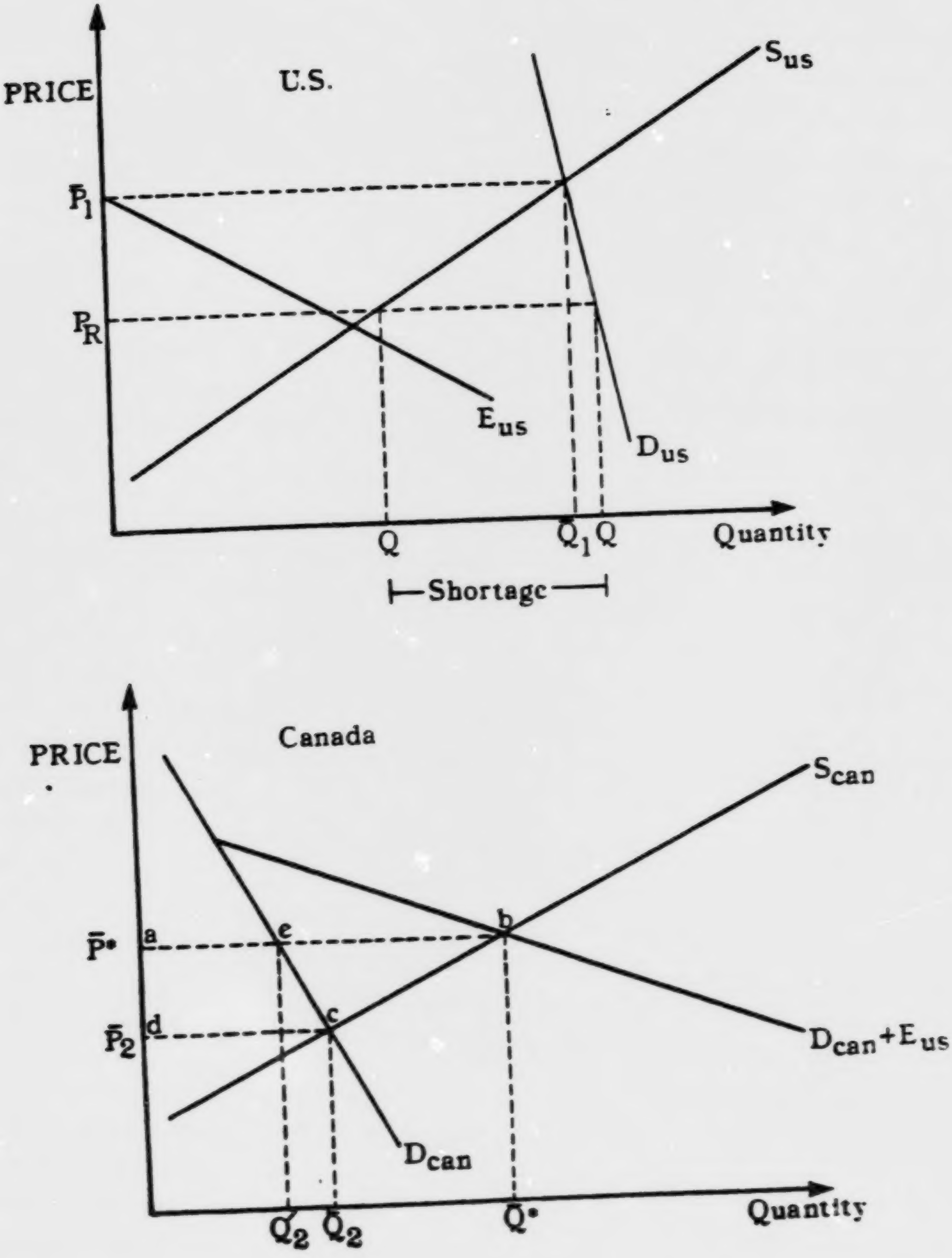


Figure 2.3: An Illustration of Possible Extremes in Export Policy

horizontally summing the E_{us} and D_{can} functions, to arrive at a total demand function, denoted $D_{can} + E_{us}$, for Canadian natural gas. Provided there were no restrictions placed upon Canadian exports to the U.S., the equilibrium price and quantity would be determined at $\overline{P}*$ and $\overline{Q}*$, where Q_2' met domestic requirements and $Q_2' - \overline{Q}*$ met U.S. demand. In the opposite extreme where export demand was precluded from the Canadian market, the equilibrium price would be established at $\overline{P}_2$.[32] Going one step further, if the U.S. maintained a ceiling price below P_R, under a policy of free trade this price would tend to be transmitted to the Canadian market along with the gas shortage situation.

Who are the gainers and losers from free trade? Producers are easily identified as gainers. They are able to sell more gas at a uniform higher price. This gain may be more precisely defined as increased rents to producers represented by the area abcd in Figure 2.3. The principal losers of such a policy are Canadian consumers who pay a higher price for a smaller quantity. Their consumer surplus is reduced by an amount represented by area aecd. Since the prime concern of the Canadian government is national welfare maximization, foreign interests are excluded from the analysis. Note, however, that U.S. consumers do enjoy a welfare gain because of Canadian natural gas exports.

Whether the nation as a whole is made better off under a policy of free trade depends upon the efficacy of the tax system. One could imagine the situation whereby the tax system failed to capture any of the increased rents (area abcd) and all rents were repatriated by a 100 percent foreign owned industry. The other extreme situation is where all rents are taxed away--'all that is, except for some undefined amount required to attract further expenditure to the search for new gas reserves'[33]--and the proceeds are returned to consumers to restore them to their 'before export' situation. Such an extreme would be in accordance with the 'Kaldor compensation principle' whereby gainers could compensate losers and still be in a better position. Reality is somewhere on the middle ground of these two extremes. However, one point may be drawn from the analysis, and that is, as the efficacy of the tax system improves (i.e., as rent taxation becomes complete) the issue of foreign ownership becomes less important.

2.6.2 Price Discrimination: The Profit Maximizing Objective

Suppose Canada can sell its gas in the two separate markets denoted Canada and United States, as shown in Figure 2.4. In theory, if Canada were to behave as a profit maximizing price discriminator, gas would be sold in that market adding most to total receipts. The profit maximizing rule under these circumstances is that gas sales should be divided between these two segregated markets in such a way as to equate the marginal revenue (MR) in both markets to the common marginal cost (MC) of total output. Referring to Figure 2.4, the profit maximizing discriminator's total output is determined at the intersection (denoted A) of the $MC_{\Sigma x}$ and ΣMR functions. The levels of output for the individual markets (x_f and x_d) which maximize profits is determined by extending a horizontal line through A and noting where it crosses MR_f and MR_d.

The equality of MR in each market, however, does not imply equality of price. Provided that the elasticities of demand are different between the two markets, price will also be different. Since $MR = P(1 - 1/E)$, provided that elasticities of demand (E) are different between the two markets and MRs are equal between them, prices (P) must differ.[34] If prices did not differ there would be no point in separating the two markets.

The equality of MRs implies:

$$P_1 (1 - 1/E_1) = P_2 (1 - 1/E_2)$$

$$\frac{P_1}{P_2} = \frac{1 - 1/E_2}{1 - 1/E_1}$$

Thus the profit maximizing price discriminator will establish a lower price in the market with the greater demand elasticity. The following analysis is based on the assumption that the U.S. demand for Canadian gas is more price elastic compared to that in Canada. Evidence which

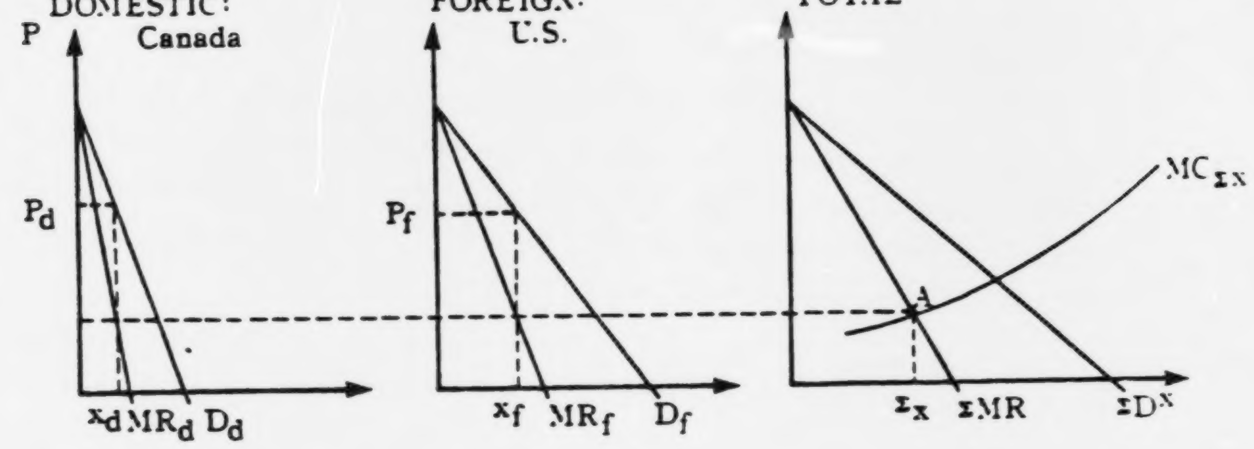

DOMESTIC:
Canada
P
P_d
x_d
MR_d
D_d
FOREIGN:
U.S.
P_f
x_f
MR_f
D_f
TOTAL
$MC_{\Sigma x}$
A
Σx
ΣMR
ΣD^x

Figure 2.4: Price Discrimination:
The Profit Maximizing Objective

tends to verify this assumption is provided by recent industry pleas to postpone a scheduled export price increase. At the current export price, the U.S. is only importing a fraction of the total gas available to it under export permits. A higher export price is only expected to exacerbate the problem. Furthermore, other U.S. policies (such as deregulating the U.S. natural gas industry, promoting energy conservation schemes and importing natural gas from Mexico) provide U.S. gas consumers with a wider range of options to importing Canadian natural gas. Economic theory suggests that the demand for a good becomes more price elastic (i.e., more price responsive) the larger the range of alternatives open to the consumer. For U.S. consumers as a whole, the range of alternatives to importing Canadian natural gas has been widening. On a regional basis, however, the scope of alternatives may be more restricted.

If one accepts the postulate that the foreign demand curve is relatively more elastic than the domestic demand function, then if Canadian policy were directed towards the maximization of profits the price of Canadian natural gas to U.S. consumers would be less than the price to domestic consumers, other things equal.

. The theory of the profit maximizing price discriminator is, however, usually used with reference to the firm whose objective is to maximize profits. Strictly speaking, the objectives of a nation with respect to the operation and maintenance of its policy are not directed towards the achievement of maximum profits. Other objectives supersede the profit maximizing goal such as protecting future domestic requirements, the maximization of domestic welfare and the maintenance of favourable international foreign relations.

The theory of price discrimination traced out in this section may be employed in a number of different circumstances besides that of the foreign trade case, as long as there are effective trade barriers to prevent consumer arbitrage. A section (Section 3.7.2) in the following chapter analyzes the price discrimination system employed in the domestic market for Canadian natural gas. Specifically, this section analyzes the incentive pricing mechanism whereby eastern Canadian consumers are offered natural gas at prices below that offered in western Canadian gas markets. The reality of this incentive pricing system may be generated employing the profit maximizing price discrimination model discussed above. Since eastern Canadians have access to relatively low priced fuel oil while western Canadians do not, the eastern Canadian demand for gas is relatively price elastic compared to that in western Canada. This fuel oil is produced by eastern refineries whereas western refineries do not produce much fuel oil because natural gas has preempted that market. Thus, in order to extend the Canadian natural gas grid eastward, gas prices in this market must be lower. The reader is referred to Chapter 3, Section 3.7.2, for further analysis of this point.

2.6.3 Price Discrimination: The National Welfare Maximizing Objective

Under the conventional theory of price discrimination (previously analyzed) whereby the pricing rule of equating the common marginal cost with the marginal revenue in each market is employed, the seller is able to maximize his profits by segregating his markets and charging different prices in each. The following analysis replaces this profit maximizing objective with the nationalistic objective of domestic welfare maximization which is treated as the simultaneous maximization of the area under the domestic demand curve (revenues plus consumer surplus) and revenue from export sales, less real resource costs (as determined by the domestic supply curve). Since this is a nationalistic objective, foreign interests, i.e., foreign consumer surpluses, are excluded from the analysis.

It should be noted that where foreign ownership arises this has implications for the allocation of rent. In an industry which is predominantly foreign owned, such as the Canadian oil and gas industry, revenues which accrue to the industry as a whole may only partially accrue to Canadians. Since foreign owned firms may repatriate their incomes (net of taxes), this must be anticipated in formulating national policy with respect to the industries in which these firms operate.[35] Rent taxation may be employed to stop the leakage of such benefits to foreign countries. To the degree that such taxation measures are successful in collecting resource rents the issue of foreign ownership dwindles in importance.

Adopting Bradley's notation,[36] the objective function may be formulated as:

$$\max \int_0^{Q_1} (P_1(Q_1))dQ_1 + (P_2(E))E - C(Q_1 + E)$$

where P_1 is the price to domestic consumers, governed by the domestic demand curve, $P_1\ (Q_1)$

P_2 is the export price, governed by the export demand curve, $P_2\ (E)$

Q_1 is domestic sales

E is export sales

C is the cost of Canadian gas

The first order condition for the maximization of domestic welfare requires that:

$$P_1(Q_1) + P_2(E) + (\frac{dP_2(E)}{dE})E = C'\ (Q_1 + E)$$

which implies that the price to domestic consumers (P_1) as governed by the domestic demand curve plus the marginal revenue from export sales

$$P_2(E) + (\frac{dP_2(E)}{dE})E$$

be equated with the marginal cost of Canadian gas ($C'(Q_1 + E)$).

Figure 2.5 shows the levels of domestic and export sales under a dual-price system governed by the strategy of national welfare maximization. Figure 2.5 is the same as the lower panel of Figure 2.3, except for the substitution of a marginal export revenue function (MR_{us}) for the U.S. excess demand function which is added to the

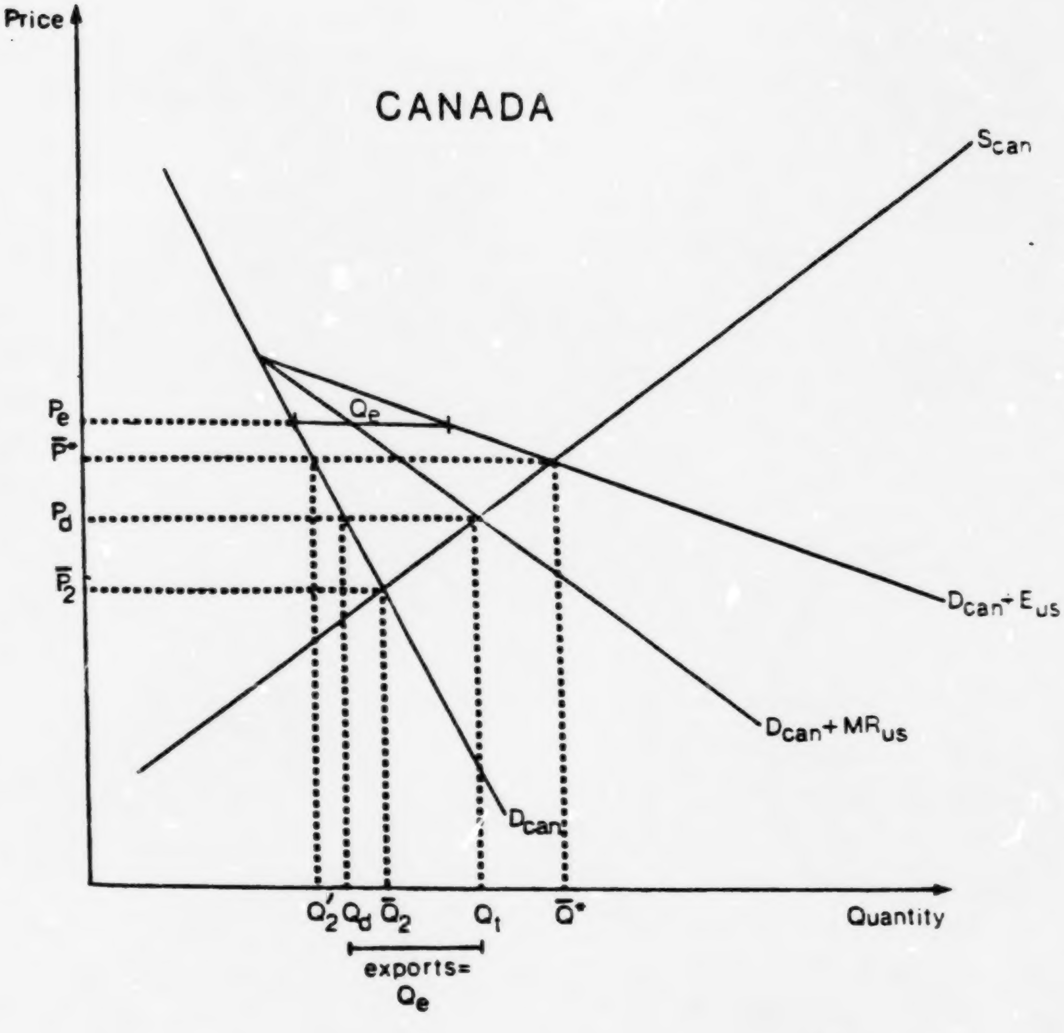

Price
CANADA
S_{can}
P_e
$\bar{P}^*$
P_d
$\bar{P}_2$
Q_e
$D_{can}+E_{us}$
$D_{can}+MR_{us}$
D_{can}
Q_2'
Q_d
$\bar{Q}_2$
Q_1
$\bar{Q}^*$
Quantity
exports= Q_e

Figure 2.5: A Dual-Price System Governed by a Strategy of National Welfare Maximization

Canadian demand curve. Thus, assuming a criterion of maximizing Canadian welfare, economic theory would suggest that the emerging dual-price system would see a higher price charged in the export market (P_e)--determined at the monopoly rule for profit maximization ($MC = MR$)--than that which is charged domestically (P_d); the latter set at the constrained competitive level.

The price charged in the domestic market (P_d) is set by extending a horizontal line from the intersection of the S_{can} and $D_{can} + MR_{us}$ curves, left to the price axis. Where this horizontal can line crosses the domestic demand curve (D_{can}) determines the quantity sold in the domestic market (Q_d). The difference between Q_d and Q_t (where Q_t refers to total production and is the quantity determined from the S_{can} and $D_{can} + MR_{us}$ intersection) is sold in the export market. The price at which it is sold is determined by finding the horizontal distance between the D_{can} and $D_{can} + E_{us}$ curves which exactly equals the distance $Q_t - Q_d = Q_e$. This price (P_e) is above the domestic price (P_d) with the corresponding difference between these prices representing an effective monopoly premium charged in the foreign market. Note also that exports (Q_e) are restricted below what they would otherwise have been under a policy of free trade, ($\overline{Q}^* - Q_2'$), a classical example of the monopolist withholding production.[37]

The price of oil, and hence gas, to Canadians is currently subsidized to below world levels. Effective trade barriers, imposed by the NEB (refer to Chapter 1, Section 1.6.2), permit prices below world levels (i.e., differential export and domestic prices) to prevail in the Canadian natural gas industry. If the domestic demand curve, in the absence of oil subsidies and government legislated domestic natural gas prices, was to produce a price of about P_d (refer to Figure 2.5) it is argued that the current arrangements are analogous to the dual-pricing mechanism discussed in this section. As is happens, the current Canadian system is a variation of the dual-pricing model discussed above, altered by the Canadian crude oil subsidization program and resulting legislated natural gas prices. The reader is referred to the succeeding chapter (Chapter 3, Section 3.7.1) which discusses the actual form that this dual-pricing mechanism takes for Canadian natural gas and the implications that this dual-pricing (i.e., price discrimination) mechanism create for the Canadian natural gas industry.

Footnotes

[1] In the Canadian economy the government has an important role in tempering the operation of the price system. Thus, the Canadian economy has been categorized a 'mixed economy' in the sense that both public and private institutions exercise economic direction.

[2] Adam Smith, The Wealth of Nations, (1776).

[3] G. C. Watkins, "Canadian Oil and Gas Pricing", Oil in the Seventies (Vancouver: The Fraser Institute, 1977), pp. 90-93.

[4] There are some international movements of natural gas by LNG (liquified natural gas) tanker. In Canada, however, there are no movements of gas by LNG tanker. The proposed Arctic Pilot Project (see Figure 1.2) is designed to produce and liquify Canadian Arctic gas and to move it to eastern Canadian markets in ice-breaking LNG tankers. If approved, this year-round operation of two 335 meter long ice-breaking tankers would be a world's first.

[5] These long lead times are generally due to the political machinery in place, regulatory requirements, extensive planning, rate and route selection, etc. All foreseeable impacts are carefully studied before pipelines are licensed and construction commences (i.e., economic, political and environmental).

[6] Transportation costs (1977 $) from Alberta to Ontario were $0.60 per million Btu for natural gas and $0.11 per million Btu for crude oil. See W. B. Friedenberg, Energy in Canada: Review and Outlook to 1995 (Calgary: Canadian Energy Research Institute, July 1979), Study No. 5. These differences could not be accounted for by variations in scale of operations or vintage differences.

[7] Leslie Cookenboo, Jr., "Production and Cost Functions for Oil Pipe Lines", Price Theory in Action (Boston: Houghton Mifflin Company, 1965).

[8] A market situation in which there is a single seller of a particular commodity or service is one of 'monopoly'.

[9] Paul A Samuelson, Economics 461 (6th rev. ed. 1964).

[10] Milton Friedman, Capitalism and Freedom 28 (1962).

[11] For a more detailed description and evaluation of the impact on the effective price of each component see Alberta Energy Resources Conservation Board, "Report on Field Pricing of Gas in Alberta" (Calgary: Alberta Energy Resources Conservation Board, 1972), Report 72-E-OG.

[12] John Helliwell and John Lester, "A New Approach to Price Setting for Regulated Pipelines", *The Logistics and Transportation Review* (Vancouver: Faculty of Commerce and Business Administration, University of British Columbia, 1976), Volume 2, No. 4, pp. 320-337.

[13] A 'common carrier' transports a commodity for a fixed charge and thus does not own the commodity being moved. As a common carrier, however, a pipeline company remains subject to the regulation of its rate of return.

[14] The main exception is Alberta Gas Trunk Line Company (AGTL, now NOVA) which transports gas destined out of the province to the Alberta border where transmission companies accept deliveries. Other pipeline companies also have some common carrier provisions.

[15] Circumstances could arise where there are several pipelines buying natural gas but where incremental purchases are concentrated in one. Such a situation would still be conducive to monopsonistic exploitation of the resource.

[16] 'Equilibrium' refers to the balancing of quantities supplied and demanded, and is characterized by the absence of endogenous pressures for change.

[17] See for instance Henderson and Quandt, *MicroEconomic Theory* (New York: McGraw-Hill Book Company, 1971). A distinction is made here between economic and social welfare, the later which presupposes the existence of a social welfare function. 'Economic welfare', as it is used here, refers to Pareto Optimality in production and consumption. That is, no producer nor consumer can be made 'better off' without simultaneously making someone else 'worse off'. There is no slack in the system (i.e., unemployed resources) and the gains to trade have been exploited (e.g., no possibility of profitable arbitrage).

[18] This is the highest offer price consistent with the transporter remaining in operation over the long term. Such an offer price would at least have to be consistent with the coverage of the transporter's variable costs in the short run.

[19] This simplification does not alter the analysis.

[20] G. C. Watkins, "Natural Gas Price Formation", 1972. (Mimeographed.)

[21] Computation of the marginal outlay (MO) is shown in the following table. Columns (1) and (2) show the supply curve (S), plotted in Figure 2.1.

(1) Units of Input	(2) Price per Unit ($)	(3) Total Cost of Input ($)	(4) Marginal Outlay($)
1	2.00	2.00	-
2	2.50	5.00	3.00
3	3.00	9.00	4.00
4	3.50	14.00	5.00
5	4.00	20.00	6.00

When one unit of input is purchased its cost is $2.00; thus the total cost of the input and total variable cost when only one unit is purchased is also $2.00. When two units of input are purchased the per unit price is $2.50. The total cost of the input is $5.00, an increase of $3.00 over the previous total cost (even though the per unit price increased by only $0.50). Thus, employing an additional unit of input increased the total cost by more than the price of the additional unit because all units are purchased at the new, higher price. The marginal outlay curve plotted in Figure 2.1 is calculated by successive subtraction in the 'Total Cost of Input' column (3).

[22] In contrast, if the pipeline purchases gas in a purely competitive market where there are many buyers, the pipeline will not be able to affect the market price of the gas by varying the amount of the gas purhcased. In this case the supply curve will equal the marginal outlay curve, and the marginal cost of gas will appear to the pipeline as an unvarying parameter.

[23] G. C. Watkins, "Natural Gas Price Formation", 1972. (Mimeographed.) This excess profit may be enjoyed by the transporter, distributor or final consumer depending upon the degree of regulation and the level of the industry upon which it is imposed.

[24] Producer surplus is the amount producers receive in excess of the minimum payment required to induce supply.

[25] Any market is said to satisfy the Pareto welfare criteria when every reorganization that augments the value of one variable necessarily reduces the value of another. Any reorganization which augments the value of one variable without concurrently diminishing the value of another variable is clearly desirable as it involves the attainment of a higher level of social welfare. Thus, Pareto optimality is a 'necessary' condition for welfare maximization. It is not, however, a 'sufficient' condition for welfare maximization. Provision of the 'sufficiency' condition requires a set of norms in the form of a social welfare function in order to render interpersonal judgements.

[26] Although prices play a key role in the changing attractiveness of industry activity (i.e., exploration, development, production, etc.) the imposed tax and incentive scheme has an overbearing impact upon the attractiveness of these activities since it is actually 'net revenues' which are of overall importance to the industry.

[27] This point was raised by G. C. Watkins in his article "Mr. Lalonde and the Price Mechanism: Or Never the Twain Shall Meet" contained in Reaction: The National Energy Program (Vancouver: The Fraser Institute, 1981). An example of an irrevocable resource loss, is the loss in production through failure to employ secondary recovery techniques. This is more applicable in the case of oil where secondary recovery is important in overall supply.

[28] Price discrimination is the sale by a single firm (in this case, a country) of the same commodity (natural gas) at two or more different prices for reasons not associated with differences in cost. Lipsey, Sparks & Steiner, Economics (New York: Harper & Row, Publishers, 1976).

[29] Tariffs (i.e., a Canadian export tax or a U.S. import tax) may also be effective barriers to trade. The federal government's National Energy Program released October 28, 1980, did not introduce an expected explicit natural gas export tax, recognizing the strong opposition of the Alberta and British Columbia governments to such an arrangement. Instead it proposed a Petroleum Compensation Charge to be levied on all natural gas sales, including those in the export market. A new tax of 8 percent to apply to net revenue from the production of oil and gas in Canada was also introduced to provide the federal government with new sources of funds.

[30] This 'producer return', generally referred to as producer 'net back', is the delivered price less transportation costs to the supply source.

[31] Faul G. Bradley, Economic Problems in the Regulation of Resource Exports: The Case of Natural Gas (Vancouver: University of British Columbia, 1972), Discussion Paper No. 92.

[32] That is not to predict the price ($\overline{P}_2$), given the likelihood of private market power and inefficient regulation rather, at the price ($\overline{P}_2$) it would be technically possible to supply Canadian demand. See P. G. Bradley, Economic Problems in the Regulation of Resource Exports: The Case of Natural Gas (Vancouver: University of British Columbia, 1972), Discussion Paper No. 92, p.16.

[33] Ibid, p. 17.

[34] The derivation for MR as a function of price and demand elasticity is as follows:

Total revenue (R) is price x quantity sold:

$$R = pq$$

Marginal revenue (MR) is the derivative of total revenue with respect to the output level:

$$MR = \frac{dR}{dq} = p + q\frac{dp}{dq}$$

Since demand elasticity (E) is defined as the absolute value of the rate of percentage change of output divided by the rate of percentage change of price:

$$E = \frac{-d(\log q)}{d(\log p)} = -\frac{p}{q}\frac{dq}{dp}$$

MR can be expressed as:

$$MR = p(1 + \frac{q}{p}\frac{dp}{dq}) = p(1 - 1/E)$$

[35] For further discussion in this area refer to J. F. Helliwell, Taxation and Energy Policy, presented to the Canadian Tax Foundation Annual Conference, 1979.

[36] Paul G. Bradley, Economic Problems in the Regulation of Resource Exports: The Case of Natural Gas (Vancouver: University of British Columbia, 1972), Discussion Paper No. 92.

[37] Refer to G. D. Quirin and B. A. Kalymon, Conservation and the Optimum Exploitation of Exhautible Resources Working Paper 73-03 (Toronto: Faculty of Management Studies, University of Toronto, February 1973), for similar results using a linear programming approach.

CHAPTER 3

THE PRICING OF CANADIAN NATURAL GAS

3.1 Introduction

The importance of price and the evolution of government in determining prices in the context of the Canadian natural gas industry have been alluded to in the two preceding chapters. The purpose of this chapter is to define the various pricing concepts or techniques as they are employed in the natural gas industry and to relate the theory of the previous chapter to actual price formation in the Canadian gas industry. In other words, what is analyzed in this chapter is dictated by the realities of what has emerged in the Canadian natural gas market.

The pricing concepts discussed in this chapter may be divided into two broad categories: regulated and non-regulated. Under the category of non-regulated pricing concepts, the net back and competitive pricing regimes are discussed. The regulated pricing concepts discussed include: Btu equivalence pricing, commodity value pricing, rolled-in pricing, incentive pricing and the maintenance of a system of dual-pricing. The latter two regulated pricing concepts listed are simply a form of price discrimination.

Regulated pricing regimes involve intervention and are implemented to achieve a purpose. Some regulated pricing regimes have been implemented in an attempt to duplicate competitive results where conditions are not conducive to competitive price formation (i.e., Btu equivalence and commodity value pricing). Other pricing regimes are designed to achieve different purposes. For example, a policy of incentive pricing may be implemented to facilitate market penetration while a system of dual-pricing may be imposed to maximize national welfare. The various purposes which these pricing regimes seek to achieve and their degree of success are discussed in turn.

3.2 Net Back Pricing[1]

Whatever the mechanism for determining the price of natural gas at Toronto, or at some other reference point, it is independent of the method used to calculate producer net backs. The Alberta field price or net back to producers is determined in a two-stage subtraction of transportation charges. First, transportation charges, Alberta to Toronto, are subtracted from the Toronto City Gate price to give the Alberta border price. Second, gathering, transmission and processing charges within Alberta are subtracted to yield a final Alberta field price (or net back to producers).

Figure 3.1 is a diagrammatic representation of the preceding calculation, showing where each of the different components (city gate price, border price) drop out in the calculation of the field price for natural gas.

Distributor and transmission margins may also be inferred from Figure 3.1. Transmission margins are the difference between the city gate price and average field price. They are generally interpreted to include transmission costs as well as a rate of return. Distributor margins are the difference between consumer prices and the city gate price and are also generally interpreted to include distributor costs plus a rate of return. Both types of margins (i.e., distributor and transmission) are normally subject to regulation.

3.3 Competitive Pricing

Economic theory suggests that, provided there are no externalities[2] in consumption and production, and markets are perfectly competitive, competitive pricing will allocate resources among various uses such that economic welfare and economic efficiency are maximized. The reader is referred to a previous chapter (Chapter 2, Section 2.2) in which the role of price in a competitive market is more fully discussed.

Under competitive conditions the 'net back' at a given supply source will be the same no matter what the market terminus. If the net

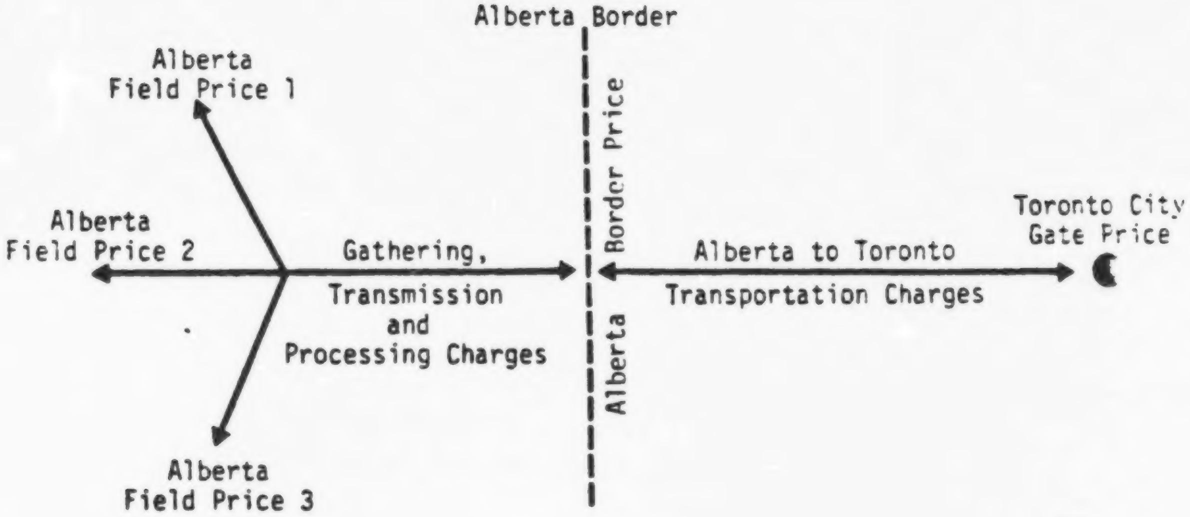

Alberta Border
Alberta Field Price 1
Alberta Field Price 2
Alberta Field Price 3
Gathering, Transmission and Processing Charges
Alberta Border Price
Alberta to Toronto Transportation Charges
Toronto City Gate Price

Figure 3.1: Determination of the Alberta Field Price for Natural Gas

back were greater due to gas being shipped to one market rather than to another, producers would sell their gas in the market returning the largest net back. With competition, these differences in net backs would be eroded and prices at the source of supply would decline until all net backs (at a given supply source) were equalized. Thus, under a competitive marketing arrangement a uniform net back will prevail at a given supply source. A competitive 'interface' will evolve where the delivered price of natural gas from one source is equalized with the delivered price of natural gas supplies from alternate sources. This competitive interface will move as producers receiving net backs significantly above marginal costs expand output increasing their marginal costs and concurrently reducing their net back. This shifting of the market interface and corresponding expansion of the gas market will be halted once the net back and marginal cost derived in the market interface are equated (MR = MC).

If Alberta were the main source of domestic gas supply and the main source of alternative supply were the southern United States, the utilization of a 'net back' pricing system would see net backs to Alberta producers decline as their gas market was extended southward. As the gas market is extended southward, the delivered price of gas from the U.S. falls since the delivery point is closer to the U.S. supply source. Thus in order to effectively compete with the incremental supply source (i.e., U.S.), Alberta gas producers must accept overall lower net backs, that is, below that which they had received prior to market expansion.

The economist's theoretical standard of perfect competition is characterized by the following: many buyers and sellers, free entry and exit from the market, product homogeneity, the absence of artificial restraints (e.g., on prices and quantities), resource mobility and perfect knowledge. For most of these requirements the Canadian natural gas industry surely falls short, whether because of imposed regulatory constraints or the mere nature of the industry itself.[3] Prior to government intervention, the Canadian natural gas industry tended to be 'monopsonistic'--dominated by a single pipeline purchaser.[4] The reader is referred to earlier discussions in Chapter 1 (Section 1.4) and Chapter 2 (Section 2.5) which describe in more detail the structure of the Canadian natural gas industry and the effects of monopsonistic price formation. The presence of monopsony, which contradicts the first characteristic of perfect competition outlined above, in part initiated government intervention in determining natural gas prices and represents a further departure from the economist's competitive model.

3.4 Btu Equivalence Pricing

Every fuel type may be expressed in terms of British thermal units (Btu) which denote the heat content of the respective fuel. A Btu is the quantity of heat required to raise the temperature of one pound of water one degree Fahrenheit. For example, one barrel of crude oil contains 5.8030×10^6 Btu while one thousand cubic feet (Mcf) of natural gas (at standard temperature and pressure) contains approximately 1.000×10^6 Btu. Thus, Btu's are a common denominator for the expression of the heat content of different fuel types. For example, purchasing a barrel of crude oil at the December 1980 price of $16.75 per barrel (Toronto City Gate) will buy 5.8030×10^6 Btu in the form of crude oil. The price for natural gas (Toronto City Gate) using 100 percent Btu equivalence with crude oil at the December 1980 domestic crude oil price would be 2.89/Mcf.[5] The 85 percent Btu equivalence price would be $2.46/Mcf.

The current regime for determining the price of domestic natural gas relies upon the Btu equivalence concept. In November of 1975 the federal and Alberta governments legislated a price for natural gas[6] which established an 85 percent crude oil Btu equivalence relationship. At that time the federal government announced its intention to see the remaining 15 percent gap eliminated over a period of 3 to 5 years. A discussion of the events culminating in this legislated pricing arrangement was presented in Chapter 1, Section 1.7. Since 1975, however, the natural gas price has slid to about 80 percent Btu equivalence with crude oil.[7]

On October 28, 1980 the federal government unveiled The National Energy Program (NEP)[8] which (unless modified) is to have wide ramifications in areas of energy production and consumption particularly as these apply to natural gas. While this new energy program still makes use of the Btu equivalence concept, gas prices to Canadian consumers under the program will rise less rapidly than oil prices in order to encourage a shift away from oil to natural gas. The 85 percent Btu equivalence relationship will be permitted to deteriorate gradually until 67 percent crude oil Btu equivalence is reached in 1983.[9] The NEP does not indicate a trend in natural gas prices after 1983. Thus, the intention of the federal government to adopt 100 percent Btu crude oil Btu equivalent pricing for domestic natural gas would appear to be abandoned, in fact, we appear to be moving in the opposite direction.

Under the new energy program the federal government will continue to establish city gate prices for natural gas shipped interprovincially although these prices will be set at the same level in Toronto, Montreal, Quebec and Halifax. The purpose of the policy is to ensure economic viability of an eastern extension of the natural gas grid to the Maritimes.

The National Energy Program also announced that a Natural Gas and Gas Liquids Tax would be levied on all natural gas sales, including those to the export market effective February 1, 1981. This new tax is scheduled to increase by $0.15 annual increments to 1983. In order to achieve the desired slower growth rate in natural gas prices to consumers, the eastern Canadian city gate price (which is posted net of the Petroleum Compensation Charge) is scheduled to increase at an even slower pace than the earlier 85 percent crude oil Btu equivalence relationship would have yielded. According to the NEP, producers are not expected to suffer any reduction in the net backs they currently receive for their domestic and export natural gas sales, although the rate of increase in producer net backs is expected to subside.[10] However, a recent study[11] contradicts those expectations--subtracting a representative set of gas pipeline tariffs from the eastern Canadian city gate prices provided in the NEP, derived Alberta border prices (annual averages) are expected to decline in nominal terms in 1982 and to decline in both 1982 and 1983 in real terms.

3.5 Commodity Value Pricing

3.5.1 Commodity Value Legislation

During the early 1970s, export demand from the United States was precluded from exerting competitive pressures in the Canadian natural gas market by the NEB's denial of additional export permits. This closure of U.S. markets coupled with the concentrated buying power of TransCanada Pipelines Limited severely impeded competition among natural gas purchasers.[12] (The reader is referred to Chapter 1, Section 1.3.3, presented earlier which discussed the development of Canadian natural gas pricing and the events which lead to TransCanada's dominance in the gas industry.)

For this reason the Alberta government, after a review of field pricing of natural gas in Alberta,[13] designed 'commodity value' legislation with the intention to simulate or approximate the impact that normal competition might have had on natural gas prices.

The term 'commodity value' is shrouded with ambiguity as it pertains to natural gas pricing analysis. The lack of any precise definition of this concept, although providing for discretion in its use, inhibits comparisons as different values may be determined using alternative methodologies.

The Alberta government defines the commodity value of gas under The Arbitration Amendment Act (1973) as:

> (i) the aggregate of the thermal value of gas determined by reference to the volume-weighted average prices of substitutable energy sources competing with gas for the various end uses of gas in the consuming markets served, directly or through exchange, by the buyer of gas under gas purchase contract,
>
> and

> (ii) the premium value of gas determined by reference to its inherent special qualities when compared with competing energy sources.[14]

As such, commodity value legislation sought to achieve a market value for natural gas based upon the value of competing fuels.

This legislation formally provided a definition of commodity value and established the circumstances under which it was to be employed. In particular, the legislation stipulated that:

> Where arbitration is conducted with respect to the redetermination of the price of gas sold under a gas purchase contract, the arbitrators shall
>
> (a) determine the field value of the gas expressed in cents per thousand cubic feet . . . [15]

where the 'field value' was defined as '. . . the commodity value of the gas less . . . transportation and distribution charges'.[16] The reader is referred to Chapter 1, Section 1.7, where the definition of 'field value' is more fully defined in an unabbreviated quotation from The Arbitration Amendment Act (1973).

However, since November 1975, the price of natural gas destined to Alberta markets for consumption has been determined under the Natural Gas Pricing Agreement Act.[17] This legislation sets the price of gas to be the lesser of the contract price (which may reflect the commodity value of the gas less transportation and distribution charges) or the net back ensuing from out-of-province (i.e., Toronto) base point markets.[18] The excerpt from the Natural Gas Pricing Agreement Act upon which the previous statement draws was presented earlier in Chapter 1, Section 1.7.

Since the Toronto City Gate price for natural gas is currently determined as a fixed percentage of the crude oil Btu equivalence price (which is also legislated at the Toronto City Gate), provided the actual crude oil price was representative of the 'commodity value' price for crude oil in the Toronto market, the resulting net back to Alberta gas producers would tend to fall short of the 'commodity value' vis-a-vis oil in the Alberta market, reflecting the relatively higher Btu costs of transporting natural gas relative to crude oil.[19] Of course, this assumes that oil is the principal alternative fuel in each market (i.e., Toronto and Alberta). Thus the further away the basing point market (i.e., Toronto) from the consuming market (i.e., Alberta), other things equal the greater will be the difference between the net backs for natural gas and crude oil and the greater the discrepancy between the 'field value' and 'net back' for gas.

The following section discusses the general methodology employed in determining the commodity value of natural gas in a given market; the subsequent section presents an example commodity value calculation.

3.5.2 General Methodology for Determining Commodity Value

Since the commodity value legislation makes explicit recognition of 'substitutable energy sources competing with gas for various end uses',[20] the commodity value of natural gas may be interpreted as the price at which consumers become indifferent between the use of gas and a mix of 'alternative' substitutable fuels. It is presumed that these 'alternative' fuels exclude natural gas as a substitute for itself as the legislation refers to sbustitutable energy sources' competing with gas'.[21] In a recent court ruling involving an interpretation of The Arbitration Amendment Act, this presumption was upheld.[22] Using economic theory, the choice of a competitive alternative would be interpreted as the selection of a least cost substitute where costs include all quantifiable costs. However, there is nothing in the legislation to exclude interpretation of the cost of an alternative as the average cost of a mix of substitutable energy sources, rather than the least cost energy source in that mix. Under The Arbitration Amendment Act (see Section 3.5.1) the commodity value of natural gas is defined with reference to 'the volume-weighted average prices of substitutable energy sources competing with gas . . .'

A commodity value calculation which acknowledges the substitutable nature of gas and alternative energy types and the indifference principle must incorporate the market prices of these alternate energy forms, but must also make appropriate use of information related to other differences in fuels and specific costs which must be incurred if one were considering a switch away from natural gas towards the use of alternate fuels. As such, information on relative thermal values, fuel efficiencies, equipment cost differentials and special qualitative differences is also required to make an appropriate commodity value calculation.

Data limitations are a restraining factor in commodity value calculations, as they are in most empirical investigations. One such data limitation relates to the attachment of a premium value for the 'inherent special qualities'[23] of natural gas compared with other fuel types, such as its relatively clean burning properties and convenience in use. Data limitations and the ambiguous nature of the type of adjustment required may preclude the inclusion of such a premium value. Where data problems of this nature have arisen, a figure of $0.10/Mcf has often been used to represent the premium value of such inherent special qualities.[24] The difficulty of determining a premium value should not preclude it from consideration in a commodity value calculation. A calculation, which excludes a premium value for inherent special qualities may be construed as setting a lower bound on the commodity value of natural gas. However, in some cases the premium value may be a discount, as in the case where there are dangers of natural gas explosions. Here, a calculation which excludes a premium discount may be construed as setting an upper bound on the commodity value of natural gas.

A commodity value calculation involves the selection of a reference point and may be interpreted as defining a 'competitive market interface' for natural gas vis-a-vis alternative fuel types. At the competitive market interface consumers remain indifferent between the use of fuels from different sources. This term (i.e., market interface), although generally used to refer to the competition for one fuel type from different sources, may be broadened in interpretation to refer to consumer indifference between different types of fuels. As such, natural gas which is priced at its 'commodity value' at the 'burner tip' defines a market interface as it makes consumers indifferent between consuming natural gas and an alternative substitutable energy type. In short, pricing natural gas at the burner-tip at its commodity value is synonymous with the establishment of a market interface. To move the reference point upstream from the 'burner-tip' to the 'city-gate', 'plant-gate' or 'field-gate' involves the subtraction of the appropriate transportation and distribution margins.

Once the reference point for the commodity value calculation is determined, the next step is to identify the most likely substitutes (actual or potential) for natural gas in each end use sector (i.e., residential, commercial, industrial). This identification process involves a number of intervening steps. First, the prices of identified substitutes are to be expressed in Btu terms (i.e., ¢/Btu). Second, these Btu prices are then adjusted to account for varying utilization efficiencies of different fuels in alternative end uses. The concept of utilization efficiency is used to refer to the ratio between useful energy output and raw energy input.[25] Third, differential equipment costs associated with the use of non-gas alternatives are calculated. This equipment cost differential should take account of varying usage rates, equipment life and interest rates. The total cost of each alternate substitutable energy form is then calculated as the sum of the equipment cost differential and the price of the energy form adjusted by an appropriate utilization efficiency factor. From this range of substitutable energy forms, adjusted for all quantifiable differences, a representative fuel is selected upon which the commodity value calculation is to be predicated.

The Arbitration Amendment Act defines the commodity value of gas by reference to

> . . . the volume-weighted average prices of substitutable energy sources competing with gas for the various end uses of gas in the consuming markets served.[26]

As such, commodity value is not a marginal but an average concept. However, where the predominance of natural gas has severely restricted competition between gas and other fuels, a calculation based upon volume-weighted average prices may not provide an appropriate measure of commodity value. Under such circumstances, observed prices may not accurately indicate relevant market substitution possibilities. That is, real relative price changes may not trigger positive substitutions between fuels. In a following section (Section 3.5.5) the possibility that market prices need not reflect the consumer's marginal rate of substitution for fuels is more fully discussed and analyzed. A portion of the final chapter (Chapter 4, Section 4.2.3) draws from this analysis to present a government policy implication of such consumer behavior.

Where the natural gas alternative has a preponderant share of the market, a commodity value calculation based on an average concept (i.e., volume-weighted) may also bias the results. A high priced (e.g., monopoly price) alternative fuel employed in a commodity value calculation may result in a high price for gas which is in relative abundant supply. For further discussion of the manner in which the underlying supply/demand situation for gas substitutes is reflected in the price for gas (i.e., using commodity value pricing), the reader is referred to a succeeding section in this chapter (Section 3.5.4).

In situations where single fuels have a preponderant share of the market, it is more appropriate to predicate a commodity value calculation on the selection of a single substitutable alternative (i.e., the least cost alternative). In cases like these, other markets where natural gas has established competitors may be used to infer potential substitutes for gas in the market concerned. Delivered prices for these potential substitutes may also then be inferred and employed in the commodity value calculation. The selection of the least cost alternative, however, provides a marginal cost interpretation to the term 'commodity value'. It could be argued that the least cost alternative is the representative fuel upon which a commodity value calculation should be based, since competition among alternative fuels themselves would lead to this solution.

Thus the burner-tip commodity value may be calculated as:

$$CV = \sum_i w_i \ \underline{\min} \ P_i^k B_i^k U_i^k E_i^k$$

where CV = commodity value

w_i = consumption weight, end use i

P_i^k = delivered price (in natural units) of kth fuel in end use i

B_i^k = Btu conversion factor for kth fuel in end use i

U_i^k = relative equipment utilization efficiency, kth fuel, end use i

E_i^k = relative equipment cost differential, kth fuel, end use i

min denotes the selection of the least cost alternative, and where the fuels considered exclude natural gas.

Commodity value as defined by the Act is not based upon any particular consideration of market structure. Market structure, however, will have some bearing on commodity value. A monopsonistic market for an alternative fuel could be characterized by prices and quantities lower than an otherwise identical market characterized by perfect competition. These lower prices and quantities would alter the commodity value of natural gas. Note, however, that a monopsonistic market at the production end does not necessarily mean a lower price to the customer (refer to earlier discussion, Chapter 2, Section 2.5).

The choice of the time period from which data are gathered to make commodity value calculations is also very important. Since the intention of a 'commodity valuation' is to represent current market values, reliance on historical price and quantity data will have implications.

3.5.3 Hypothetical Commodity Value Calculation

A hypothetical commodity value calculation is carried out below using the City of Medicine Hat as the reference point 'burner tip'. The three end-use sectors--residential, commercial and industrial--are identified, and available and potential alternatives and their perceptible costs in each of these sectors are dealt with in turn.

In the Medicine Hat residential sector, the selection of alternatives to natural gas is obscured by the absence of established competitors. Thus, to identify potential substitutes the method employed is to look at alternative markets where natural gas does have established competitors. For example: light fuel oil (LFO), electricity and propane have established themselves as firm competitors to natural gas in British Columbia and Ontario residential markets. Average delivered prices of these fuels to the Medicine Hat residential market are assumed[27] to be:

Fuel	Average Delivered Price ($/natural unit)	Average Delivered Price ($/MMBtu)
LFO	$0.80/gallon	$4.80/MMBtu
electricity	$0.05/kW.h	$14.65/MMBtu
propane	$0.50/gallon	$4.60/MMBtu

These Btu prices are then adjusted to account for the utilization efficiency of these fuels relative to natural gas in the residential sectors. Historically, the utilization efficiencies of these fuels in the residential sector have been established as: natural gas (75 percent), LFO (65 percent), electricity (100 percent) and propane (75 percent).[28] As such, the Btu price of propane is left unaltered, a 10 percent adjustment is added to LFO and a 25 percent adjustment is subtracted from electricity. These adjustments are made in order to satisfy the indifference principle, a principle characterizing consumsers at the market interface (see discussion above). The rationale as to whether the calculated adjustment should be added or subtracted from the Btu prices is as follows. Since electricity is 25 percent more efficient relative to natural gas, fewer Btu's are purchased in the form of electricity than in the form of natural gas to obtain the same useful energy output, and thus the 25 percent difference in relative efficiencies of these fuels is subtracted from the electricity Btu price. The same rationale, but in reverse, is applicable to the LFO adjustment and the case of propane is strikingly obvious. The adjusted Btu prices are as follows:

Fuel	Average Delivered Price Adjusted for Fuel Efficiency ($/MMBtu)
LFO	$5.28/MMBtu
electricity	$10.99 MMBtu
propane	$4.60/MMBtu

The next step is to make an adjustment to account for equipment cost differentials associated with the use of each fuel type. Since space heating and water heating are the two largest uses for natural gas in the Medicine Hat residential sector, the focus on equipment cost differentials relates primarily to differences in furnace and storage tank costs. Once this equipment cost differential is identified, assumptions are made as to the life expectancy of such equipment, household energy consumption rates and interest rates on capital equipment. These assumptions may then be employed to calculate the appropriate equipment cost differential. For example, assume that an installed fuel oil furnace costs, on average, $400 more than a natural gas furnace. Assuming a 20 year equipment life, a 15 percent interest rate and an 150 MMBtu level of annual energy consumption in the household the appropriate equipment cost differential to be added to the LFO price would be $0.21.[29] This calculation is repeated for each fuel in the residential sector and the resulting total cost of each alternate substitutable energy form is calculated as the sum of the equipment cost differential and the adjusted Btu price of the energy form:

Fuel	Total Cost of Alternate Fuel Type ($/MMBtu)	Assumed Equipment Cost Differential ($/MMBtu)
LFO	$5.49/MMBtu	($0.21)
electricity	$11.99/MMBtu	($1.00)
propane	$5.20/MMBtu	($0.60)

Given these relative price relationships, propane is selected as the competitive (i.e., least cost) alternative for natural gas in the residential sector.

This process of identifying the competitive alternative to natural gas is repeated for the other end use sectors: commercial and industrial. It is assumed LFO is identified in the commercial sector as the least cost alternative (i.e., $5.00/MMBtu) and heavy fuel oil (HFO) as the least cost alternative (i.e., $3.00/MMBtu) in the industrial sector.

Having identified the least cost alternative in each end use sector, the next step is to combine these alternatives to arrive at an overall commodity value for natural gas. This is accomplished by weighting each end use sector by annual consumption figures as follows:

Sector	Assumed Consumption Weight (%)	Assumed Alternate Fuel Cost ($/MMBtu)
residential	30	$5.20
commercial	30	$5.00
industrial	40	$3.00
average	100	$4.26

Thus, the commodity value of natural gas in this hypothetical example is $4.26/MMBtu. Average distribution margins may be deducted from this 'burner tip' value to yield corresponding downstream values such as 'city gate', 'field gate', etc.

It should be noted that employing historical consumption figures for determining consumption weights assumes consumers' demand demand for specific fuels is perfectly price inelastic. Economic theory, however, would suggest that consumers will consume less of the commodity whose real relative price has increased. Thus, historical consumption weights may not be a representative of the new equilibrium after a price increase of a natural gas substitute (e.g., HFO in the industrial sector), although for small price changes, short run analyses and/or inelastic demand, these historical consumption weights may serve as an adequate approximation to the actual shares. After a large price increase, however, it may be necessary to re-determine the commodity value, employing new consumption weights which capture the long run adjustments to the price increase made by consumers.

As the preceding example shows, determination of appropriate commodity values is a detailed and time consuming task, and to add to its labourious computation it must be repeated for each end-use market for which a commodity value is sought.[30]

3.5.4 Commodity Value Pricing: A Surrogate for Competition?

Implicit in the commodity value calculation is the assumption of 'perfect substitutability' between natural gas and a 'selected'[31] competitive alternative in each end use sector. By perfect substitutability it is meant that natural gas and its alternative supply identical services in identical proportions.[32] Given identical prices (e.g., $1.00/million output Btu) for two perfectly substitutable resources, a rational consumer would be indifferent between consuming equal amounts of each resource.

Economic theory suggests that a perfectly competitive market in which there are perfect substitutes available would be characterized by a uniform price for such substitutes at equilibrium. Commencing from a position of two distinct market prices, these two prices would converge to a uniform level since consumers provided with perfect substitutes would switch to the consumption of the least cost alternative.

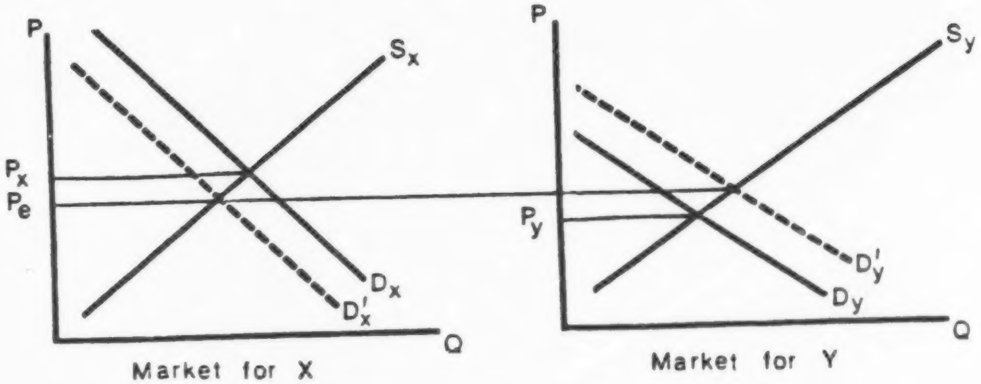


Figure 3.2: Determination of a Uniform Price for Perfect Substitutes

In Figure 3.2 above, the market demand and supply curves of two perfect substitutes (X and Y) are represented, with corresponding prices (P_x and P_y) determined at the respective intersections of these curves.[33] The relative scarcity of comodity X prescribes a relatively higher price for this commodity ($P_x > P_y$) in the short run.[34] Informed and rational consumers of commodity X, recognizing that they can satisfy their demands for the identical services provided by both X and Y at an overall lower cost, will purchase Y and will refrain from purchasing X. This switch in demand will shift the demand curve for Y out to D_y' bidding up the price to P_e and shift the demand curve for X down to D_x' letting the price decline to P_e. The price P_e is the equilibrium price and will prevail in both the X and Y markets concurrently. Thus the assumption made above, that there be identical prices (e.g., $1.00/million output Btu) for the two perfectly substitutable resources, would appear tautological. Provided that these markets are perfectly competitive, in equilibrium and that the two resources are perfect substitutes in the end use sector, economic theory would suggest that their prices should be identical.

A complication arises when resources are consumed across a range of end use sectors. For the above analysis to apply in such circumstances, the two resources must be perfect substitutes in each end use sector served. Each consuming sector must be characterized by consumer indifference to equal amounts of the two 'perfectly substitutable' resources. Under such circumstances, economic theory would again suggest the prevalence of a uniform price for the perfectly substitutable resources.

The commodity value calculation makes implicit use of this economic theory. After making explicit adjustments for equipment cost differentials, utilization efficiency, etc., the commodity value calculation seeks to determine a market value for gas based upon the value of competing alternatives. These adjustments are made to nullify the quantifiable differences of the fuels considered and are assumed to provide consumer indifference. Thus the consumer, while faced with different fuels at different prices, would remain indifferent between consuming natural gas and an alternative fuel in each end use sector. While there is a price differential, the consumer does not prefer one fuel over another since this price differential is exactly balanced by the value the consumer places upon the differences of the fuels in delivering a particular service.

Thus far, the commodity value calculation appears to hold up under the auspices of a few strong assumptions. The economic validity of the commodity value calculation takes its sharpest blow when this consumer indifference is not established in all consuming sectors. In the case of natural gas this is particularly important since natural gas, as well as being consumed as an energy source, is also consumed as a non-energy input (as a feedstock) in the petrochemical industry. In 1979, approximately 13 percent of the natural gas consumed in Alberta was consumed as a feedstock in the petrochemical industry.[35] In order to maintain the degree of economic validity which the commodity value calculation had to this point, natural gas would have to have an identified substitute in this sector as well which could, in some manner, be incorporated into the commodity value calculation. Since natural gas consumed as a feedstock is a non-energy use for this commodity there would be no purpose in determining its value in this sector (petrochemical) on a Btu basis compared with, for example, coal or crude oil. The Btu (British thermal unit) measures the energy content of fuels and is no basis for determining the efficiency of use of natural gas as a non-energy petrochemical feedstock.

Since the commodity value legislation defines the commodity value of natural gas with reference to the thermal value of the gas it is implied that the non-thermal value of the gas is not to be reflected in the commodity value determination. This would imply a form of market segmentation in the application of the legislation. However, since natural gas is demanded in non-energy uses economic theory would suggest that this use for gas should, in some manner, be reflected in the value attached to gas.

One further issue relating to the commodity value calculation concerns the manner in which the underlying supply/demand situation for a natural gas substitute may be reflected in the price of natural gas. Assume, for example, that we are interested in determining the commodity value of natural gas where all natural gas substitutes are in extremely short supply. This shortage situation for gas substitutes would, providing markets were operating efficiently, cause an increase in the market price for these fuels relative to other prices in the economy. Also, assume that natural gas was relatively plentiful and, in equilibrium, were priced accordingly (i.e., relatively lower prices). Implicit in this example is that natural gas and its alternatives are not 'perfect substitutes' since this, in equilibrium, would be reflected by identical prices being established for all the fuels (i.e., natural gas and its perfect substitutes). The reader is referred to the illustration (Figure 3.2) represented earlier.

Now suppose the government steps in to regulate natural gas prices, deeming that the current market price does not reflect the 'true' commodity value of the gas. Determining the commodity value of the gas where identified substitutes are relatively higher priced would translate to a higher price for gas. Thus, the underlying supply/demand situation for gas substitutes is reflected in the price for natural gas. In this example, the commodity value calculation resulted in a price increase for gas, yet gas was in abundant supply.

To extend the analysis further: one can infer by implication the effect that commodity value pricing would have on the markets of substitute fuels. A relatively higher price established for gas strengthens the competitive position of the substitute fuels vis-a-vis natural gas. Furthermore, a commodity value price for gas charged in the non-thermal sector, but determined without consideration to the non-thermal uses (i.e., petrochemical) of natural gas, would be tantamount to opportunity cost pricing. Opportunity cost pricing refers to pricing according to the best alternative use foregone. A good analogy here is that of the world price for oil, which is the opportunity cost of oil to Canadians. For each barrel of oil consumed at the domestic price, Canadians forego the revenues that could have been generated by exporting that barrel of oil at the world price. Whether the world oil price is a monopoly price is irrelevant, it remains the opportunity cost of oil. The same can be said for natural gas; regardless of whether the natural gas price is a legislated commodity value price, this price is the opportunity cost of natural gas--excluding the export market. For each Mcf of gas consumed in the petrochemical industry, Canadians forego the opportunity of selling that gas at its commodity value as an energy input.

3.5.5 Commodity Value Pricing: The Impact of Specialized Consumption Patterns

The purpose of the proceeding section is to analyze the impact that specialized consumption patterns have in the interpretation of commodity value pricing. As was alluded to earlier (Section 3.5.2), circumstances may arise where 'observed' market prices may not reflect the rate at which the consumer is willing to substitute one fuel for another. This has definite consequences in the interpretation of commodity value pricing since it is 'observed' market prices upon which these commodity value price determinations are based.

This analysis begins with a look at the role of price in the market for conventional goods and services setting out the optimizing criterion of the consumer in these circumstances. The analysis then compares these results to the results generated in the market where consumption patterns are specialized.

In the market for conventional goods and services, relative prices serve a rationing role whereby optimizing consumers purchase commodities by allocating their income so that the last dollar spent on any two goods brings them equal satisfaction. Following this optimization process by consumers, economic theory[36] suggests that the marginal rate of substitution of any two goods[37]--say X for Y (MRS_{XY})--should equal the relative price of Y to X. This relationship is expressed as follows:

$$MRS_{XY} = \frac{MU_Y}{MU_X} = \frac{P_Y}{P_X}$$

where MU_X and MU_Y denote the marginal utility[38] of X and Y respectively, and where P_x and P_y denote the respective prices of X and Y. That is, given the market prices facing the consumer, in equilibrium every consumer purchases that quantity of each good so that the rate at which he is willing to substitute one good for another is equal to the rate at which he can substitute them in the market.

An exception to this general theory is provided by specialized consumption patterns whereby the standard indifference curve analysis, for a single consumer, provides a 'corner' solution. A corner solution, sometimes called a boundary solution, is characterized by a positive consumption level of one good and a zero consumption level of an alternative good in a two commodity indifference curve analysis. Standard indifference curve analysis, however, assumes an interior solution whereby consumption levels of both goods are positive.

Fuels are one such consumer good whose consumption is typically specialized. For example, consider space heating: if the price of light fuel oil rose, the consumer would purchase less light fuel oil

(LFO) in total but would not partially substitute quantities of other fuels in its place. The consumer would wait until such time as it was to his benefit to make a complete conversion to an alternative fuel. The use of a principal fuel (i.e., there are no alternative fuels used in conjunction with a principal fuel) by a consumer establishes his consumption pattern as specialized. That is, the consumer does not consume a 'mix' of different fuels but consumes a single fuel (i.e., specialized consumption). Figure 3.3 below illustrates the indifference analysis where consumption patterns are specialized. Note that the following analysis is a long run analysis; substitution possibilities are curtailed in the short run.

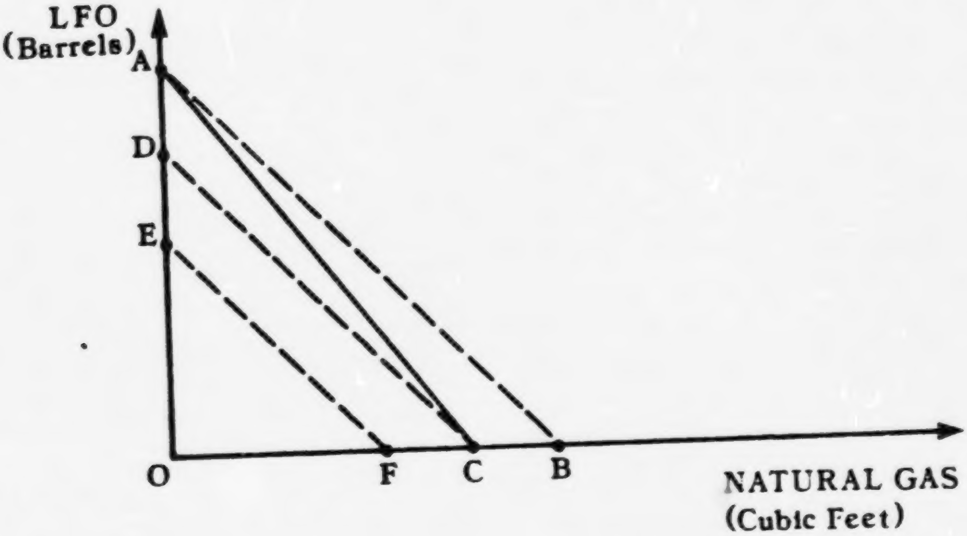


Figure 3.3: Consumer Equilibrium-Specialized Consumption

In Figure 3.3, let the slashed line AB denote the consumer's indifference curve whereby the consumer is indifferent between any point on AB. Generally, indifference curves are drawn convex to the origin representing a diminishing marginal rate of substitution.[39] The indifference curve represented in Figure 3.3, however, is drawn as a straight line which extends to each axis. The underlying assumption of this straight line indifference curve is that the consumer is willing to substitute LFO and natural gas at a constant rate (i.e., constant marginal rate of substitution). In producing the consumer good 'space heating', the two fuels may be substituted in fixed proportions yet leaving the consumer indifferent as to the relative proportions of fuels consumed.

An analogy may be drawn here between the consumer and the firm. In the production sector, the demand for energy is 'derived' from the demand for the firm's output. In the household sector, the consumer's demand for energy is also a 'derived' demand. Energy is not demanded for its own sake but as an input to produce other goods and services (i.e., space heating, lighting, transportation, etc.). Since Btu's are homogeneous the consumer is willing to substitute one input Btu for another input Btu at a constant rate (i.e., at a constant rate equal to one). However, the consumer does not purchase Btu's directly but purchases fuels which have Btu's embodied in them. Furthermore, these fuels are not perfect substitutes (i.e., non-homogeneous). Fuels differ by various factors (e.g., Btu content, relative combustion efficiency, burning properties) so that the consumer has a preference as to the type of fuel which he purchases. These other factors will affect the rate at which the consumer is willing to substitute one fuel for another but these are constant over the range of substitution possibilities. Thus, the marginal rate of substitution is constant, which is reflected in a straight line consumer indifference curve.

To determine the slope of the indifference curve (i.e., the marginal rate at which the consumer is willing to substitute the two fuels) one must examine the physical charteristics of each fuel. Initially, assume that only the heat content (i.e., British thermal units) of the fuels is important in determining the marginal rate of substitution of the two fuels. Since one barrel of LFO contains 5.8275×10^6 Btu's and one thousand cubic feet of natural gas contains 1.000×10^6 Btu's, in terms of Btu, the consumer would be willing to substitute one barrel of LFO for approximately 5.8 thousand cubic feet (Mcf) of gas.

There are other physical characteristics of fuels which are important to the consumer and which this indifference curve should reflect. For example, the relative combustion efficiencies of the fuels should be considered. Other characteristics which the indifference curve would reflect include the relative equipment cost differential incurred by choosing one fuel over another and any inherent special qualities of either fuel (e.g., clean burning properties, ease of use, etc.). To the extent that each of these characteristics are important to the consumer, the slope of his indifference curve would be altered.

Referring back to Figure 3.3, let the line segment AC represent the budget constraint of the consumer. Point A $(=Y/P_{LFO})$ represents the situation in which the consumer spends his entire income (Y) on LFO. Where P_{LFO} denotes the market price of LFO. Similarly for C $(=Y/P_{NG})$, where this time the consumer's income is expended entirely on natural gas (NG). The consumer's budget will allow him to purchase any combination of LFO and natural gas which is on the budget constraint curve AC. Standard consumer theory assumes that there are only two goods and a limited money income (Y) so that along the budget line AC the consumer is assumed to spend the whole of his income. For the consumer, however, it is not a matter of spending all his income on fuel. For this reason, one may choose to consider the budget line as representative of a budget share for fuels, say $p_f q_f$, which is constrained by Y and the prices and quantities of all other goods and services.

The consumer is further limited in his choice of fuel combinations by a technical constraint imposed by the fuel using equipment. Current technology does not allow the consumer to concurrently burn natural gas and LFO in a single space heating system. For the consumer, it is not an 'and/or' choice. His choice to use one fuel automatically precludes his use of another fuel.[40] Thus, the consumer must be located at either A or C in Figure 3.3, using either all LFO or all natural gas (i.e., the solution set is restricted to a single corner solution).

Assume that initially the consumer is in equilibrium at A where he purchases OA barrels of LFO and zero Mcf of gas. The consumer prefers point A over point C because he is clearly on a higher indifference curve at A. Had the consumer initially been at point C, it would definitely have been to his advantage to switch to the use of LFO as he would enjoy a higher level of well-being by doing so (e.g., increasing the temperature of space heating).

Now assume, other things equal, that the price of LFO increases. As the price of LFO increases the consumer will, over some range of prices, continue to purchase LFO but in smaller quantities. This behavior is represented by a downward pivoting of the budget constraint curve in Figure 3.3 around C. Between point A and point D the consumer is unable to achieve a higher level of well-being by switching fuels. Once the budget curve has pivoted sufficiently to make it parallel to the consumer indifference curves, to position DC, (i.e., the consumer's budget line lies on his indifference curve), the consumer becomes clearly indifferent between using LFO and natural gas. Although he must choose one fuel over another he has no criterion, leaving expectations aside, on which to base his choice. Switching fuels will leave his level of well-being unaltered.

As the relative price of LFO increases above that implicit in the budget line DC, a threshold price for LFO, the consumer will move to C. At C the consumer is able to achieve a higher level of well-being than had he remained using LFO (because he will be on a higher indifference curve). This move is a long run activity involving the installation of natural gas burning equipment by the consumer and resulting in his purchasing OC Mcf of natural gas and zero barrels of LFO.

The conclusion to be drawn from the above analysis is that market prices need not reflect a unique marginal rate at which consumers are willing to substitute one good for another. It may take significantly higher relative prices before consumers would be willing to substitute one fuel for another. In this sense, market prices may tend to underestimate the marginal rate at which substitution of one fuel for another will occur. Also, this analysis brings to light an apparent inconsistency in the theory (i.e., continuity of substitution). At point A in Figure 3.3, further substitution of natural gas for LFO cannot occur so that the marginal rate of substitution cannot exist there, it is literally undefined at A (and other corner solutions).[41]

Establishing a 'commodity value' price for natural gas is supposed to provide for consumer indifference between natural gas and its alternatives. In the context of Figure 3.3, the commodity value of natural gas would only be reflected in the relative prices implicit in the budget line DC. Along DC the consumer is indifferent between using LFO or natural gas. In summary, the object of the commodity value pricing exercise may be viewed as determining a relative price for natural gas which would line up (i.e., make them parallel) the consumer's budget line with his indifference curves. Any attempt to determine a commodity value price for gas which does not do this would leave the consumer with a clear preference and would defeat the object of the exercise.

3.5.6 Commodity Value Pricing: Conclusions

While the theory of commodity value pricing may be intuitively appealing, it is not pragmatic. Data limitations abound preventing the kind of 'fine-tuned adjustments' required for an accurate commodity value measure. Further, there is the general issue of relying on regulated pricing mechanisms (as opposed to unregulated) in determining prices. It is the underlying demand/supply situation of a particular good which should be reflected in the price of that good, not the demand/supply situation of another good. As such, commodity value pricing, as with any regulated pricing mechanism, may only be defended as a means for correcting for short term market distortions. Commodity value pricing should not be relied upon for long term price determination.

3.6 Rolled-In Pricing

When different sources are supplying one market at various costs the price in the market may be rolled-in. Instead of hitting the consumer with a melange of prices for the same commodity--one for each supply source--one price is calculated in which costs of different supply sources are blended together. This is usually done using some manner of weighting system whereby the costs at large supply sources figure more heavily into the 'rolled-in' price (i.e., average pricing). This type of pricing scheme is predominant in gas and electricity pricing arrangements whereby one market is served by one pipeline or high voltage transmission line but which is gathering gas or electricity from various sources.

Currently the cost of liquefied natural gas (LNG) and synthetic natural gas (SNG) from coal and petroleum feedstocks are significantly higher than the average price for natural gas at the wellhead. In the United States, pipelines are seeking to average the higher prices for these supplemental supplies with supplies under existing contracts and use the rolled-in prices for prospective purchasers. These pipelines defend pricing on a rolled-in basis and are opposed to pricing on an incremental or differentiated marginal cost basis which they argue would handicap the financing of new projects as demand may be dampened at these higher (incremental) prices. The U.S. Federal Power Commission (FPC) in a landmark decision determined that the distribution of LNG from Algeria should be done on an incremental basis.[42] The basic argument advanced against rolled-in pricing is that it neither provides for allocative efficiency nor equity. Natural gas consumers which do not receive the benefits from non-conventional sources (i.e., LNG) are burdened with its cost under a rolled-in pricing regime, whereas pricing on an incremental or differentiated marginal cost basis (e.g., vintage pricing) does not impose such burdens. Under a policy of incremental pricing, only those consumers benefitting from higher cost sources of supply are asked to pay higher prices.

In Canada there is also significant SNG potential as well as Arctic gas to supplement existing natural gas supplies. Since these two supplemental sources are relatively more costly to develop, compared with supplemental gas supplies from conventional sources, rolled-in pricing is a potential issue for Canada. As conventional gas sources are depleted the economics of these non-conventional sources should become more attractive. This, of course, assumes gas prices escalate to reflect the relative scarcity of natural gas. Pricing on a rolled-in basis may initiate premature additions of new supplies as their costs may be spread over all purchasers rather than incremental purchasers. However, if a policy of gradualism is thought to be important, pricing on a rolled-in basis mitigates the adjustment process of bringing on higher cost sources of supply. Furthermore, when pipeline tariffs are also rolled-in, this mitigates the initial pipeline tariff problem (i.e., where the pipeline tariff is higher in real terms to initial users than to later users).

Under an alternative marginal cost pricing scheme, which establishes a single price to apply to different sources of supply, or a rolled-in pricing regime, substantial economic rents will accrue to producers with costs substantially below the current price level. Generally, these higher rents are enjoyed by producers operating on older reservoirs. A scheme of incremental or marginal cost pricing, whereby different prices apply to different sources of supply (for example, vintage pricing), has the advantage of avoiding these rent distribution problems.[43] A differentiated marginal cost pricing scheme (i.e., a scheme of vintage pricing extended to the consuming market) would be analogous to a perfectly discriminating monopolist. However, it has the added dilemma of requiring decisions as to which users should be allowed to purchase the lower priced sources of supply. This problem may be solved by charging consumers an average price but continuing to employ a scheme of vintage pricing on the supply side. This solution, however, has problems associated with it as it gives rise to excess demand and an associated economic loss.[44]

3.7 Price Discrimination

The price discrimination models described in Chapter 2 (Sections 2.6.2 and 2.6.3) are a reasonable approximation to the realities of the Canadian natural gas market. On the international scene Canada maintains a system of dual-pricing, charging a higher price in the U.S. market than that which is charged domestically. Such a pricing scenario imitates the results which would be generated under the price discrimination model discussed in Chapter 2 which sought to maximize national welfare (refer to Section 2.6.3). In the following section (Section 3.7.1), the characteristics of the particular system of dual-pricing which has emerged for the Canadian natural gas exports scene are discussed and analyzed. This analysis investigates the effects of this form of price discrimination on Canadian natural gas producers.

The profit maximizing price discrimination model, which was also discussed earlier (Chapter 2, Section 2.6.2), may be employed to discuss and analyze the realities of the domestic natural gas market. This analysis is presented in a subsequent section (Section 3.7.2). Specifically, this model may be used to generate the realities of the Canadian incentive pricing arrangement, which is merely a disguised system of price discrimination.

3.7.1 A System of Dual-Pricing

Canada currently maintains a system of dual-pricing for domestic and export natural gas sales. The domestic price of natural gas ($CDN·2.30/Mcf) is legislated in order to preserve approximately 85 percent Btu crude oil equivalence at the Toronto City Gate. A uniform export price for natural gas is legislated at the international boundary. This export price is currently (or was until earlier last year) based upon the substitution value of crude oil imported into eastern Canada. This is calculated by

> . . . taking the cost of imported oil at Montreal without the subsidy, adding the oil toll from Montreal to Toronto, deducting the cost of transmitting gas from Alberta to Toronto and adding on the average cost of transmitting Canadian gas to the international boundary.[45]

The natural gas price derived from this formula (sometimes referred to as the Lalonde-Duncan formula) is somewhat below the Btu equivalent price of OPEC (Organization of Petroleum Exporting Countries) crude oil landed in eastern Canada because of the higher transportation cost of moving gas from Toronto to Alberta than to the Canada-U.S. border. The current legislated export price for Canadian natural gas is $US 4.94/Mcf.

Regulatory distortions in the 'net back' procedure discussed earlier (Section 3.2) have produced a bias in the existing system whereby producers prefer moving incremental gas production through the export market than through domestic channels. The current dual-price system maintained for Canadian natural gas, whereby an approximate $3.00 price differential--$CDN 5.23 (export), less $CDN 2.30 (domestic), less royalties and taxes--is returned to producers on a pro rata basis, provides producers with increased net backs as a result of gas moving through the export market. This scheme eliminates competition among producers for access to export markets for their particular production volumes since each producer is rewarded on the basis of their production volumes rather than on the proportion of that volume which reaches the export market. In effect, gas supply is not segregated by market destination.

Although the amount of gas sold in the export market is regulated, the more gas that is vented through this channel the higher the overall net back to all natural gas producers. Thus, the earnest requests on the part of producers wishing to move more gas through the export market may be accounted for by two complementary factors. The first is that authorization of additional exports would open new markets for significant volumes of shut-in Canadian gas. This would provide needed cash flow to further exploration and development activities. The second is that every incremental unit sold in the new export market contributes to a larger overall net back for all producers whether or not a particular producer's gas is sold in the export market. This second factor also provides an explanation for the active producer lobbying and pressure on regulatory boards for the approval of additional exports. Lobbying on the part of producers for the extension of the Canadian natural gas grid (i.e., extension to Vancouver Island, Q & M's extension east to Maritimes) has been less vociferous.

3.7.2 Incentive Pricing

As argued earlier (see Chapter 2, Section 2.6.3), if Canada were to act nationalistically, with no consideration to the welfare (i.e., the economic bargaining power) of foreigners, a dual-price system would emerge in the Canadian natural gas market. Within this system, the price in the export market would be set at a monopoly level and the domestic price would be set at competitive levels (i.e., lower than the export price). Note, however, that although the domestic natural gas price is currently less than the export price it is so mainly on account of subsidized oil prices (and hence gas prices) rather than competitive conditions in the domestic natural gas market. Further, it can be argued that this lower domestic price should apply to all domestic gas, and not just gas destined to new markets. Such a differentiation would be tantamount to price discrimination among Canadian consumers, and this would require justification on grounds other than economic efficiency.[46]

Q & M (Quebec and Maritimes) pipelines contend[47] that if the Canadian natural gas grid were to be extended eastward, the natural gas price in this market would have to be established at an appropriate level. Spokesmen for Q & M maintain that the appropriate level is 65 percent of the crude oil Btu equivalent, which is markedly below the current domestic price for gas. The reader is referred to Chapter 2, Section 2.6.2, which sets the conditions (i.e., relative price elasticities) which determine the relative levels at which prices are to be set by a discriminating monopolist. It is argued that in order for natural gas to achieve significant market penetration it must be priced competitively with substitute fuels. In eastern Canada, gas's closest substitute is light fuel oil. Available at relatively low prices, light fuel oil currently fulfills the majority of the space-heating requirements east of Montreal. However, it should be acknowledged that electricity usage in this area has recently shown a rapid increase. If natural gas were to make significant in-roads into what has historically been a fuel oil market, it must be priced appropriately. It is further argued that conversion to the use of an alternative fuel type requires the conversion of fuel-using apparatus. Since this is a costly alteration for fuel oil consumers to make, especially when it may involve the premature retirement of equipment, this increases the need to set an appropriate price for natural gas vis-a-vis fuel oil (i.e., provide incentive natural gas prices).

If expansion of the Canadian natural gas grid were to be achieved solely by an incentive pricing scheme, the price for gas sold in established markets vis-a-vis new markets would not decline. Thus, producer net backs would only be reduced for gas sold in new markets. Under competitive conditions, such circumstances would not arise (refer to a Section 3.3 presented earlier). These circumstances depict price discrimination--markets are divided, supply is segregated and there is no potential for arbitrage. Under these circumstances producer net backs would differ, implying well head prices would vary by market destination.

In contrast, under competitive conditions in the domestic market, market expansion would be predicated upon the level of surplus gas to be supplied domestically (i.e., after extraction from total supply of those quantities destined for export markets at monopoly prices, refer to Section 3.7.1). Such a gas surplus would be disposed of by a uniform reduction in gas prices to all consumers. This uniform reduction in price would induce gas market expansion in established areas, since it would promote further displacement of natural gas substitutes, and extension to new areas; whereas an incentive pricing scheme (i.e., selective price reductions), would only promote gas usage in new areas. Historically, gas market expansion eastward has been achieved through such a uniform pricing approach rather than a system of price discrimination (i.e., incentive pricing).

Footnotes

[1] For a more detailed analysis of the 'net back' procedure and discussion of the evolution of a competitive delivered price structure see M. A. Adelman, The World Petroleum Market (Baltimore: The John Hopkins University Press, 1972), Chapter V.

[2] Externalities (also called third party effects) are effects, either good or bad, on parties not directly involved in the production or consumption of a commodity.

[3] For a discussion of the regulatory bodies affecting the industry see Chapter 1, Section 1.6. The nature of the natural gas industry is discussed in Chapter 1, Section 1.4.

[4] Refer to Table 1.3 presented earlier.

[5] This Btu equivalence calculation assumes that one thousand cubic feet (Mcf) of gas contains one million Btu (MMBtu). Thus, $2.89/Mcf = $2.89/MMBtu.

[6] The reader is referred to Chapter 1, Section 1.7, which discusses the development of the role of regulation as it affects natural gas pricing.

[7] The reader is referred to The National Energy Program, 1980 for a more complete review of crude oil and natural gas prices. Department of Energy, Mines and Resources, The National Energy Program (Ottawa: Department of Energy, Mines and Resources, 1980), p. 32.

[8] Ibid.

[9] Note that any natural gas price (or energy price for that matter) can be expressed as a proportion of Btu equivalence with crude oil by simple arithmetic.

[10] Producer net backs have increased from $0.08/Mcf in 1970 to $0.37/Mcf in 1975 and $0.94/Mcf in 1979. Ibid., p. 31.

[11] See G. C. Watkins, "Mr. Lalonde and the Price Mechanism: Or Never the Twain Shall Meet" in Reaction: The National Energy Program (Vancouver: The Fraser Institute, 1981, p. 60, Tables II and III.

[12] Refer to Chapter 1 for a more detailed discussion of the events culminating in the legislation of natural gas prices.

[13] Alberta Energy Resources Conservation Board, "Report on Field Pricing of Gas in Alberta" (Calgary: Alberta Energy Resources Conservation Board, August 1972), Report 72-E-OG.

[14] Province of Alberta, The Arbitration Amendment Act, R.S.A. 1973, Chapter 88.

[15] Ibid. Also see Section 16.1.

[16] Ibid.

[17] Province of Alberta, The Natural Gas Pricing Agreement Act, S.A. 1975, Chapter 38.

[18] The reader is referred to an earlier section entitled "Net Back Pricing", which discusses how this net back procedure operates.

[19] Transportation costs (1977 $) from Alberta to Ontario are $0.60 per million Btu for natural gas and $0.11 per million Btu for crude oil. See W. B. Friedenberg, Energy in Canada: Review and Outlook to 1995 (Calgary: Canadian Energy Research Institute, July 1979), Study No. 5. These variations could not be accounted for by variations in scale of operations or vintage differences.

[20] Province of Alberta, The Arbitration Amendment Act, R.S.A. 1973, Chapter 88.

[21] Ibid.

[22] See Reasons for Judgement, Mr. Justice W. A. Stevenson, re Interpretation of The Arbitration Amendment Act, December 1979. The judge in coming to his conclusion, however, made a distinction between 'value' and 'price'. He says:

> . . . 'value to owner', 'value to taker', 'market value' and 'price' which are separate concepts that may coincide or coalesce in a given case. The legislature required the arbitrators to determine a value (which may or may not be reflected in the market price) and to use it 'in fixing' the price. It is not used 'to fix the price' nor is it 'to be' the price.

In an appeal to this judgement the above distinction was not upheld, that in fact the field value so determined was 'to be' the price.

Otherwise, to permit distinction would be to circumvent the legislation. See Reasons for Judgement, Mr. Justice Leiberman re Appeal of Interpretation of The Alberta Arbitration Amendment Act, June 1980.

[23] Province of Alberta, The Arbitration Amendment Act, R.S.A. 1973, Chapter 88.

[24] Based on discussions with G.C. Watkins, President, DataMetrics Limited, Calgary, and Visiting Professor of Economics, University of Calgary.

[25] It is well known that this ratio which measures 'utilization efficiency' has changed over the years predominantly towards the fuller utilization of inherent energy contained in the commodity. Utilization efficiency is dependent upon the end uses to which energy commodities are put, the equipment in which they are used, and the type of energy commodity used. See A. P. Ellison, "An Input-Output Analysis of the Effects of Rising Energy Costs on Canadian Industries" (Calgary: Canadian Energy Research Institute, April 1979), Working Paper 79-1, p. 192.

[26] Province of Alberta, The Arbitration Amendment Act, R.S.A. 1973, Chapter 88.

[27] The prices assumed for this example commodity value calculation are approximate figures. To obtain information about the actual costs of these fuels would entail contacting various sources such as oil refiners, propane distributors and electrical utilities. The data used in the commodity value calculation contained in Chapter 3 are similar to the data used in a DataMetrics report entitled "The Commodity Value of Natural Gas in the Canadian Western Natural Gas Service Area", Report No. 99, (Calgary: DataMetrics Limited, October 1979).

[28] See A. P. Ellison, "An Input-Output Analysis of the Effects of Rising Energy Costs on Canadian Industries" (Calgary: Canadian Energy Research Institute, April 1979), Working Paper 79-1, p. 192.

[29] This is calculated as though the $400.00 were borrowed today at 15 percent interest rates to purchase a piece of equipment with a 20 year life. Annual payments of such a loan amortized over the 20 year equipment life would be $63.90. Assuming 150 MMBtu as average annual household energy consumption, the appropriate equipment cost differential is $0.21/MMBtu ($63.90 ÷ 150 MMBtu).

[30] The methodology for the preceding example is based upon a study by DataMetrics Limited entitled The Commodity Value of Natural Gas In The Canadian Western Natural Gas Service Area completed for Shell Canada Resources Limited, June 1980. This reference is made with the expressed permission of Shell Canada Resources Limited.

[31] Economic theory would suggest that the 'selection' criterion be the choice of a least cost alternative, although the legislation (The Arbitration Amendment Act - refer to Section 3.5.1) may be interpreted differently.

[32] H. A. John Green, Consumer Theory (Baltimore: Penguin Books Inc., 1971), pp. 156-158.
For example, assume that heavy fuel oil and natural gas supply identical amounts per unit consumed of the services: home heating (h) and home lighting (l). The assumption is made that quantities h and l in one million Btu of each resource considered are objectively measurable and that neither resource possesses inherent characteristics which the other does not possess (e.g., cleaner burning properties, ease of use, etc.).

[33] For illustrative purposes, this example has been restricted to the analysis of two perfect substitutes. The analysis may be extended to any number of substitutes without alteration of the results.

[34] The manner in which we arrive at this starting point is unimportant (e.g., regulated price differences, the introduction of a new commodity, etc.) Of more importance is that prices are free of regulatory restraints and move in response to shifts in demand.

[35] Alberta Energy Resources Conservation Board.

[36] See for example Henderson and Quandt MicroEconomic Theory (New York: McGraw-Hill Book Company, 1971).

[37] The 'marginal' rate of substitution measures the number of units of a good a consumer is willing to sacrifice in order to receive an additional unit of an alternative good.

[38] Marginal utility refers to the incremental satisfaction gained from consuming the last unit.

[39] For example, consider the case where a consumer's utility is dependent upon his levels of food and home heating consumption. If the consumer has no home heating but some food he may be willing to forfeit several units of food to get one unit of home heating. Once his home has reached a comfortable living temperature he may only give up a fraction of a unit of food to get an additional unit of heating (i.e., diminishing marginal utility of home heating). One can imagine the situation where the consumer has reached a saturation point where he is no longer willing to substitute one good for another.

[40] In the industrial market dual-fired systems are in use and there is no reason in principle why this could not apply to the residential market. Should the use of dual-fired systems extend to the residential sector some time in the future, then the analysis contained herein for residential heating would not be directly applicable.

[41] For further discussion (and a proof) see Peter Newman, The Theory of Exchange (New Jersey: Prentice-Hall, Inc., 1965), pp. 39-40.

[42] Columbia LNG Corp., et al, Opinion No. 622 (June 28, 1972) and Opinion No. 622-A (October 5, 1972), 47 FPC 1624 and 48 FPC 723. Remanded by U.S. Court of Appeals, 491 F. 2d 651 (5th Circuit, March 25, 1974), on the issue of incremental pricing.

[43] Vintage pricing applies to 'old' and 'new' sources of supply (i.e., temporal distinction) and as such is a particular case of differential pricing. The reader is referred to G. C. Watkins, "Canadian Oil and Gas Pricing", Oil in the Seventies (Vancouver: The Fraser Institute, 1977), pp. 113-115, for further discussion of vintage pricing.

[44] Ibid., p. 119 for a discussion of the economic losses associated with vintage pricing.

[45] Canada, National Energy Board, "Report to the Governor in Council in the Matter of the Pricing of Natural Gas being Exported under Existing Licences" (Ottawa: National Energy Board, January 1980).

[46] The following analysis is based on G. C. Watkins, "Natural Gas Pricing: Current Issues and Implications", November 1978, (mimeographed).

[47] See National Energy Board, Reasons for Decision in the Matter of the Applications Under Part III of the National Energy Board Act of TransCanada Pipelines Limited and Q & M Pipe Lines Ltd., April 1980.

CHAPTER 4

SOME CONCLUSIONS AND POLICY IMPLICATIONS

4.1 Introduction

The following chapter addresses several pricing policy issues raised by the preceding analysis. The chapter is directed towards resolving some of the questions raised in the INTRODUCTION to this thesis. To recapitulate:

> Should the conditions in one market be allowed to dictate prices in other markets, and if so under what conditions should such a pricing mechanism be permitted to prevail? What are the implications for Canada of the maintenance of a dual-price system such as that which exists for the domestic and foreign natural gas markets? Does, in fact, the potential presence of monopsony power prescribe government regulation of prices?

4.2 Legislated Natural Gas Prices

4.2.1 Btu Equivalence Pricing

One issue raised by the preceding analysis is the economic validity of the current policy of legislating natural gas prices. Legislated Btu equivalence pricing may be defended as a suitable pricing policy for the short term, when there is a lack of competition among buyers in the market place resulting in monopsonistic exploitation of the resource. In the long term, however, Btu equivalence pricing is more difficult to defend; it may become inefficient and distortive. A policy of 100 percent Btu equivalence pricing assumes perfect substitutability between different energy resources. Even if there were this perfect substitutability between energy resources, this would not automatically prescribe 100 percent Btu equivalence pricing as the appropriate thermal equivalence--this depends upon the particular demand and supply situation for the resource (i.e., natural gas). A policy of 85 percent Btu equivalence, although it does not assume perfect substitutability, may also set an inappropriate price. An inappropriate price for gas--a price which did not reflect its true scarcity or inherent special qualities, for example, would cause consumers and producers to react to distorted price information. It may be that the 'correct' (free competitive market determined) price for natural gas should settle well below the legislated 85 percent Btu crude oil equivalence price, as the current surplus natural gas situation would intimate.

The conclusion to be drawn is that only if the relative prices of oil and gas are allowed to adjust in response to market forces will their economic equivalence in use be determined. The maintenance of Btu equivalence prices for different fuel types makes as much sense in principle as the maintenance of calorie-equivalent prices for different foods.

4.2.2 Commodity Value Pricing

The economic validity of defining natural gas prices on a commodity value basis may be criticized on the same ground as Btu equivalence pricing. As an interim measure to correct for short run distortions, commodity value pricing has some merit. The demand for natural gas could outstrip supply if prices were, for some reason, inhibited from responding to demand pressures. This, it has been argued, was the circumstance encountered in the early 1970s where gas prices were held below competitive levels by the dominant purchasing position of a single pipeline--TransCanada Pipelines Limited. Over the longer term, however, pricing gas according to some formula, such as commodity value or 85 percent Btu equivalence, is not an economically valid procedure as it does not reflect the true nature of the market involved. The relative scarcity of a particular commodity should be the prime determinant of price, not the value calculated in a simple mathematical relationship. More specifically, whereas Btu equivalence pricing sets the price for gas on the basis of one fuel type (i.e., crude oil), the determination of price using commodity value is loaded completely onto a mix of other fuels. Thus neither pricing regime heeds the particular supply and demand situation for gas itself.

4.2.3 Incentive Pricing

A simple government policy implication may be drawn from the preceding analysis of specialized consumption patterns (refer to Chapter 3, Section 3.5.5). Suppose that government is concerned about the intensive use of oil in the economy and instead desires to promote natural gas consumption.[1] If observed market prices were assumed by government to reflect the marginal rate at which consumers are willing to substitute natural gas for oil, government may not react appropriately. They may perceive that, for example, a 10 percent relative price increase for oil will cause consumers to switch to the use of natural gas. However, since the initially observed market prices may tend to underestimate the marginal rate of substitution, it may take substantially higher relative prices or considerable time[2] before consumers are willing to substitute the consumption of natural gas for oil. In that case, a 10 percent relative increase in the oil price may not produce its desired effect (i.e., fuel conversion) but may be merely an inflationary price increase (i.e., increase costs to the user).

4.3 A Policy of Deregulation and Escalation

The following analysis is made with reference to Figure 4.1 which pertains to the domestic natural gas market. Later the analysis is broadened to include export policy. This figure is representative of the current domestic natural gas market which at current prices (85 percent crude oil Btu equivalence) is characterized by an exigent natural gas surplus. This gas surplus is represented in Figure 4.1 as the distance XY, an amount by which supply exceeds demand at the regulated 85 percent rule price. Price P_e, is the equilibrium price, a price which will exactly balance demand and supply. Economic theory suggests that only this price, P_e, will maximize the benefits of exchange (i.e., consumer surplus + producer surplus are at a maximum).

Therefore at a higher than equilibrium price of 85 percent, consumer surplus is represented by the area A and producer surplus by the areas 1, 3 and B. At this price only $Q_{85\%}$ will be purchased.

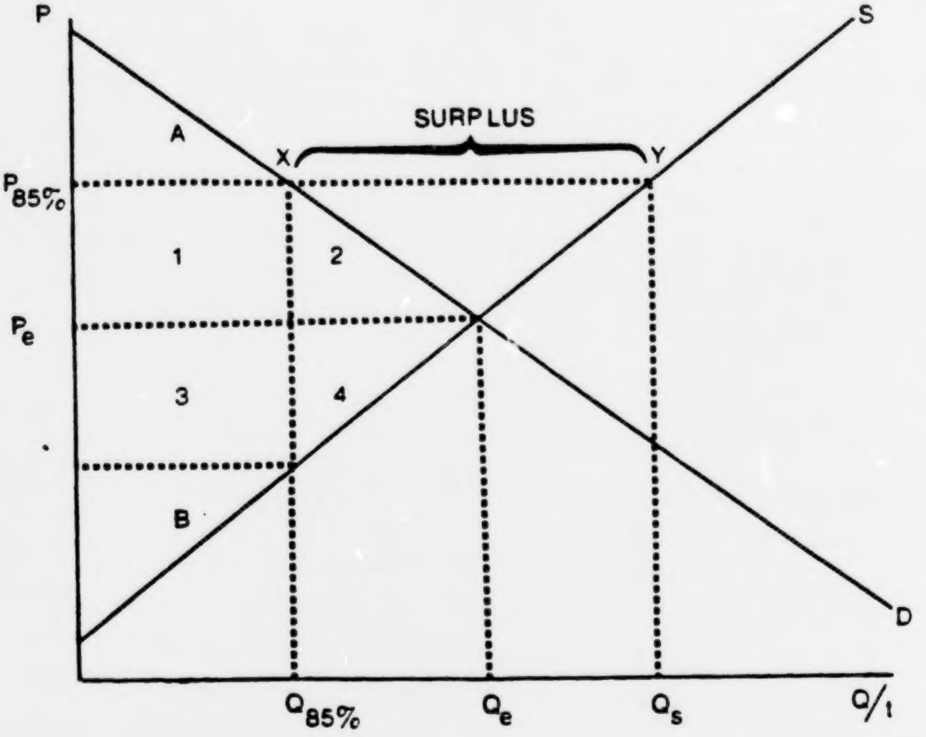

P
S
SURPLUS
A
X
Y
$P_{85\%}$
1
2
P_e
3
4
B
D
$Q_{85\%}$
Q_e
Q_s
Q/t

Figure 4.1: The Effects of Competitive Price Formation

Although producers could make available Q_s to the market, consumer demand of an equivalent amount is forestalled by too high a price.

A reduction in the price to P_e would provide a gain in consumer surplus represented by the areas 1 and 2 and a gain in producer surplus represented by the area 4. Area 1 represents a transfer of surplus, it is lost by producers but is picked up by consumers at the lower price, P_e. The areas 2 and 4 represent marginal additions to surpluses owing to additional exchanges taking place at the lower price. These additional exchanges all take place at a uniform price P_e. Price P_e, however, is in excess of the minimum amount necessary to elicit Q_e in supply (producer surplus = B + 3 + 4) and is less than the maximum amount which consumers would have paid to acquire Q_e (consumer surplus = A + 1 + 2). As such both consumers and producers benefit from marginal gains in their respective 'surpluses' by being able to trade Q_e at the uniform price P_e compared to the situation of being able to trade only $Q_{85\%}$ at the higher price $P_{85\%}$.

The overall conclusion to be reached from such an analysis is that a move from $P_{85\%}$ to P_e will result in a net gain represented in Figure 4.1 by the areas 2 and 4. A reduction in price which only approaches P_e will also produce an overall net gain to both producers and consumers taken together but this net gain will also only approach the maximum attainable net gain at P_e.

It is clear then, that a move from $P_{85\%}$ to P_e would result in an overall net gain when both producers and consumers are considered in totality, although it is not so clear whether producers alone would benefit from such a move. This would depend upon the relative sizes of the areas 1 and 4 which in turn depend upon the shape of the particular demand and supply functions considered. It is clear, however, that consumers would benefit from such a move as they suffer no loss in surplus but only stand to gain by being able to consume more units at an overall lower price.

If the analysis were broadened to consider the issue of natural gas exports, the results of the analysis would be somewhat altered.

Referring back to Figure 2.5 (Page 53, Chapter 2), price $\bar{P_2}$ would correspond to price P_e in Figure 4.1. In Figure 2.5, however, price $\bar{P_2}$ was not advocated as maximizing the net gain to Canadian consumers and producers. Rather, a higher price (P_d in Figure 2.5) was advocated as providing maximum benefits to Canadians (i.e., consumers and producers). The decision to maximize national welfare in an open economy (refer to Chapter 2, Section 2.6.3) would prescribe a higher price for natural gas (i.e., higher than price P_e in Figure 4.1) in the domestic market. Under such a scenario consumers would lose as they would be charged a higher price and consume a smaller quantity. However, consumers' losses would be outweighed by the gain to Canadian producers in the export market (i.e., revenues from export sales). The reader is referred to Chapter 2, Section 2.6.3, for a more detailed analysis of the type of dual-pricing system which emerges from the adoption of a nationalistic objective function in an open economy. A succeeding section (Section 4.5) in this chapter further addresses the issue of export policy.

The manner in which domestic gas prices are to be freed up remains to be discussed. It is not suggested that all relevant regulation be relinquished immediately. Rather, a program of gradualism is suggested whereby regulated gas prices are lowered in a step process, eroding the gas surplus and mitigating the adjustment process. Under the National Energy Program, 1980 the federal government has designed a pricing schedule for natural gas (this was discussed earlier in Chapter 1, Section 1.7) which is in accordance with a policy of gradualism as suggested above. Within this program, natural gas is to be priced at 67 percent of the Btu equivalence with crude oil by 1983. Although there is uncertainty as to whether this 67 percent pricing relationship will set the appropriate price for gas, it is probably closer to the mark than the current relationship which sets the price at approximately 85 percent. The only means of ascertaining whether the '67 percent' price is the appropriate price would be to deregulate gas prices (given constraints on exports) once the 67 percent level had been achieved. The existence of a natural gas surplus (or shortage), however, could be used to indicate whether there would have to be a further decrease (or increase) in the price.

It is not suggested that this deregulation policy be extended to the export market. It would seem to be in the national interest that gas prices be set at monopoly levels by a monopoly body (i.e., federal government) than to have individual gas producers compete for U.S. consumers.

While freeing of natural gas prices will erode the current gas surplus and provide for a more efficient allocation of resources, there will still be a long run misallocation of resources as long as the domestic oil price is maintained below the world level. Natural gas, being crude oil's closest substitute in the domestic market, is undervalued to the extent that domestic crude oil prices are maintained below their opportunity cost, the world price.

Freeing the domestic natural gas price appears to be only part of the solution towards an efficient allocation of resources. Steps must be taken to see that natural gas is properly valued relative to the 'true' value of alternate fuel types. The 'true' value of a fuel would refect its relative scarcity--in the case of crude oil the world price is deemed to reflect the relative scarcity of this fuel type. The current domestic crude oil price is subsidized to below world levels. Thus, the second half of the solution could be to raise the domestic crude oil price towards the world level as rapidly as possible without causing undue hardship on Canadian crude oil consumers.[3] This could be done in a series of step price increases which would aid in mitigating the adjustment process. In this manner, natural gas consumers will not be unduly biased against the consumption of natural gas vis a vis crude oil. Allowing the domestic crude oil price to approach world levels will have other beneficial effects for the Canadian economy. Higher crude oil prices will forestall increases in crude oil demand and concurrently bring on additional supplies. These two forces will have the complementary effect of bringing us closer to the federal government's crude oil 'self-sufficiency' objective. Higher crude oil prices will allow consumers to make proper valuations of the natural gas they consume. Demand for natural gas will increase as consumers recognize its true value relative to other fuels. This increased demand may help to offset or may more than offset the fall in gas prices which is expected at the introduction of deregulation of gas prices. The net effect on natural gas prices will depend upon the relative strengths of the opposing forces: deregulation of gas prices amid surplus conditions versus escalation of the crude oil price towards the world level. Only if the relative prices of oil and gas are allowed to adjust in response to market forces will the economic thermal equivalence of these two fuels be determined. It may be that the regulated 85 percent oil-Btu-equivalence rule is a good way off the mark.

While a combination policy like that proposed (i.e., deregulation of gas prices and escalation of the crude oil price towards world levels) may do much to see that natural gas is priced in the market place at its competitive market value, this policy does not assure that gas producers concurrently receive competitive field value (i.e., equivalent of competitive market value, determined at the competitive market interface, less transportation and distribution margins which include a normal rate of return) for this same gas. Since natural gas pipeline companies in general own the gas that is transmitted they have the opportunity to extract rents or 'supernormal profits'. Regulation of pipeline companies' rate of return, however, makes extraction of such 'supernormal profits' difficult to maintain.

4.4 Addressing the Issue of Windfall Profits

Accepting the economic importance (i.e., gain in efficiency) of allowing crude oil and natural gas prices to generally approach world levels, it is necessary to recognize the size and nature of the rents accruing to the holders of mineral rights. A policy of price escalation would have the effect of creating windfall profits[4] or rents for those parties holding mineral rights to proven reserves.[5] These windfall profits have the potential of greatly enhancing industry cash flow while the higher prices (i.e., world levels) will enlarge the size of the reserve base. The result may be a degree of investment in exploration, development and distribution facilities, providing a supply of oil and gas in excess of domestic requirements and thus furthering pressure for greater export outlets.

To the extent foreign ownership is present, repatriation of windfall profits to foreign shareholders is of concern. Provided that this element of pure rent (i.e., windfall profits) accruing to producers is continuously reinvested in the Canadian economy or is appropriated by government, the accrual of windfall profits by foreign firms is a less pressing issue. It is probably in this area, however, that public policy is weakest in terms of providing appropriate tax measures. The appropriate tax measures must be sensitive to differential rents accruing in various projects.[6] An insensitive tax regime may discourage investment in marginal projects in an attempt to capture all of the resource rents.

In this latter regard it may be advantageous for provinces, conferred with the responsibility of general administration of natural resources within their boundaries, to be left with the first responsibility for designing and implementing an appropriate tax and incentive scheme which they view to befit the industry. Their advantage stems from proximity. Provincial activities in monitoring physical production and their capabilities of more fine-tuned monitoring of costs and financial data place provincial authorities in a position capable of relatively more efficient appropriation of differential rents accruing on production from different resources, locations, grades, processes, and timing of production.[7] The federal authorities, however, must take the major responsibility beyond production taxes. The federal government, conferred with the powers of taxation (i.e., the corporate income tax), is charged with the responsibility of collecting residual rents escaping provincial production taxes (i.e., royalties). Such residual rents would include those passed up and down the chain of vertical integration. Recent confrontations between the federal and Alberta governments, however, indicate that the federal government would like more powers than it presently possesses as the residual rent collector.

4.5 Implications for Export Policy

Some interesting implications for export policy arise out of the analyses presented earlier (Chapter 2, Section 2.6.3, and Chapter 3, Section 3.7.1) concerning the emergence of a dual-price system governed by a strategy of national welfare maximization. Provided national welfare maximization was the intended objective of Canadian natural gas export policy, it would appear evident that Canadian natural gas prices (i.e., domestic and export) are set at appropriate relative levels. That is, higher prices are charged in the export market than those which are charged domestically, indicating that Canadian gas exports receive a premium. Whether this premium reflects a 'monopoly' premium or a competitive price based upon substitution value in the U.S. market is unclear, since oil is subsidized in the Canadian domestic market. This premium (i.e., export price less domestic price) is returned to producers on a pro rata basis, as was discussed earlier in Section 3.7.1. This procedure partially avoids the effect of price discrimination (i.e., dual-pricing) on the producers, as it eliminates competition among producers for access to the export market. However, the effect of price discrimination is not completely avoided by this pro rata payment scheme. There remains a bias amongst producers as a group to vent additional gas through the export channels, since this would result in an increase in their overall net backs, given the price differentials.

Footnotes

[1] See Energy, Mines and Resources, Canada, The National Energy Program, 1980, (Ottawa: Energy, Mines and Resources, Canada, 1980), pp. 79-87.

[2] If a firm does not have dual burning capacity, it may substitute fuels only after a considerable lag in time. The firm may be captured in the sense that it may find it economical not to change equipment until present stock becomes obsolete or worn out. For those firms whose present equipment stock is ready for replacement, their fuel demand will be flexible and they are expected to install new equipment which will burn that fuel which is anticipated to be most economical over the life of the new equipment. As a further reference see G. C. Watkins, "Canadian Residential and Commercial Demand for Natural Gas" (Calgary: University of Calgary, May 1974), Discussion Paper No. 30

[3] While the impact of a crude oil price increase may be softened by more gradual escalations as opposed to a once and for all sharp increase, consumers are still going to have to bear the burden of the long time maintenance of crude oil prices below their true value, i.e, the world price. For further discussion of the ramifications of a sharp increase in the Canadian crude oil price see G. E. Angevine, The Impact of a Sharp Oil Price Increase. (Calgary: Canadian Energy Research Institute, June 1980), Study No. 11.

[4] Windfall profits or economic rent is that return in excess of that which is necessary to maintain resources in their current employment. Thus, its taxation will not affect resource allocation.

[5] Proven reserves are quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in the future from known oil and gas reservoirs under existing economic and operating conditions. See A. P. H. Van Meurs, Petroleum Economics and Offshore Mining Legislation (Amsterdam: Elsevier Publishing Company, 1971), p. 15.

[6] The Alberta royalty scheme, which distinguishes between 'old' and 'new' production according to the date of discovery, charges a relatively higher royalty on 'old' production recognizing the existence of windfall profits on reserves proven under earlier economic and operating conditions and the relatively higher costs of exploration and development of 'new' reserves. See W. B. Friedenberg, Z. C. Slagorsky, and A. J. Walsh*, "Government Incentives in Canada's Petroleum Industry" (Calgary: Canadian Energy Research Institute, March, 1980), Working Paper 80-1. *nee: A. J. Nixon.

[7] T. L. Powrie, W. D. Gainer, Canadian Policy Toward Trade in Crude Oil and Natural Gas (Ottawa: Economic Council of Canada, 1976).

BIBLIOGRAPHY

Adelman, M. A. *The World Petroleum Market*. Baltimore: The Johns Hopkins University Press, 1974.

Alberta. Alberta Energy Resources Conservation Board. *Conservation in Alberta, 1971*. Calgary: Alberta Energy Resources Conservation Board, 1972.

________. Alberta Energy Resources Conservation Board. *Report on Field Pricing of Gas in Alberta*. Report 72-E-OG. Calgary: Alberta Energy Resources Conservation Board, August 1972.

________. Alberta Energy Resources Conservation Board. *Review of Field Pricing of Gas in Alberta*. Report 73-I-09. Calgary: Alberta Energy Resources Conservation Board, August 1973.

________. Alberta Energy Resources Conservation Board. *Report on Field Pricing of Gas in Alberta*. Report 74-P. Calgary: Alberta Energy Resources Conservation Board, August 1974.

________. Alberta Energy Resources Conservation Board. *Alberta Oil and Gas Industry Annual Statistics*. Report 80-17. Calgary: Alberta Energy Resources Conservation Board, 1979.

________. Alberta Energy Resources Conservation Board. *Alberta's Gas Supply Protection, Procedures and Formula*. Report 79-I. Calgary: Alberta Energy Resources Conservation Board, December 1979.

________. Provincial Court. *Reasons for Judgement*. re: Interpretation of the Arbitration Amendment Act, December 1979.

________. Provincial Court. *Reasons for Judgement*. re: Appeal of Interpretation of the Arbitration Amendment Act, June 1980.

________. Statute of Alberta. *Gas Resources Preservation Act, 1949*. Chapter 157, Paragraph 7 (3).

________. Statute of Alberta. *Gas Resources Preservation Act, 1956*.

________. Statute of Alberta. *Energy Resources Conservation Act, 1971*. Chapter 30.

________. Statute of Alberta. *The Arbitration Amendment Act, 1973*. Chapter 88.

———. Statute of Alberta. *The Natural Gas Pricing Agreement Act, 1975*. Chapter 38.

Angevine, G. E. *The Impact of a Sharp Oil Price Increase*. Study No. 11. Calgary: Canadian Energy Research Institute, June 1980.

Berndt, E. R. and Watkins, G. C. "Demand for Natural Gas: Residential and Commercial Market in Ontario and British Columbia." *Canadian Journal of Economics* 10, February 1977.

Berndt, E. R., and Wood, D. O. "Technology, Prices and the Derived Demand for Energy." *Review of Economics and Statistics*, 1975.

Bradley, P. G. "Economic Problems in the Regulation of Resource Exports: The Case of Natural Gas." Discussion Paper No. 92. Vancouver: University of British Columbia, Department of Economics, June 1972.

Breyer, Stephen, and MacAvoy, Paul W. "The Natural Gas Shortage and the Regulation of Natural Gas Producers." *Harvard Law Review* 86, 1973.

Canada. Department of Energy, Mines and Resources. *An Energy Policy for Canada*. Vols. 1 and 2. Ottawa: Supply and Services Canada, 1973.

———. Department of Energy, Mines and Resources. *An Energy Strategy for Canada: Policies for Self Reliance*. Ottawa: Department of Energy, Mines and Resources, 1976.

———. Department of Energy, Mines and Resources. *Oil and Natural Gas Resources of Canada, 1976*. Report EP 77-1. Ottawa: Supply and Services Canada, 1977.

———. Department of Energy, Mines and Resources. *The National Energy Program 1980*. Ottawa: Department of Energy, Mines and Resources, 1980.

———. National Energy Board. *Canadian Oil Supply and Requirements*. Ottawa: National Energy Board, September 1978.

———. National Energy Board. *Canadian Natural Gas Supply and Requirements*. Ottawa: National Energy Board, February 1979.

———. National Energy Board. *Reasons for Decision in the Matter of Applications under Part VI of the National Energy Board Act of Alberta & Southern Gas Co. Ltd., et al*. Ottawa: National Energy Board, November 1979.

———. National Energy Board. *Annual Report 1979*. Ottawa: Supply and Services Canada, March 1980.

________. National Energy Board. *Report to the Governor in Council in the Matter of the Pricing of Natural Gas Being Exported Under Existing Licences*. Ottawa: National Energy Board, January 1980

________. National Energy Board. *Reasons for Decision in the Matter of the Applications under Part III of the National Energy Board Act of TransCanada Pipelines Limited and Q & M Pipe Lines Ltd.* Ottawa: National Energy Board, April 1980.

________. Statistics Canada. *The Crude Petroleum and Natural Gas Industry*. Catalogue No. 16-213, 1954-1978.

Canadian Petroleum Association. *Statistical Handbook*. Calgary: Canadian Petroleum Association, 1979.

Cookenboo, Leslie, Jr. "Production and Cost Functions for Oil Pipelines." *Price Theory in Action*. Boston: Houghton Mifflin Company, 1965.

Crommelin, M., and Thompson, eds. *Mineral Leasing as an Instrument of Public Policy*. Vancouver: University of British Columbia, 1977.

Crommelin, M.; Pearse, P. H.; and Scott, A. "Management of Oil and Gas Resources in Alberta: An Economic Evaluation of Public Policy." *Natural Resources Journal* 18, April 1978.

DataMetrics Limited. *The Industrial Demand for Oil and Gas in Ontario*. Study No. 2. Calgary: Canadian Energy Research Institute, March 1978.

________. *The Value of Wabamun Coal*. Report No. 86. Calgary: DataMetrics Limited, October 1978.

________. *The Commodity Value of Natural Gas in the Canadian Western Natural Gas Service Area*. Report No. 99. Calgary: DataMetrics Limited, October 1979.

________. *The Commodity Value of Natural Gas in the Canadian Western Natural Gas Service Area*. Report No. 105. Calgary: DataMetrics Limited, June 1980.

________. "Notes on Commodity Value and its Determination." Calgary, 1980. (Mimeographed.)

Ellison, Anthony P. "Past and Future Energy Costs in the Canadian Economy." Working Paper 78-3. Calgary: Canadian Energy Research Institute, April 1978.

________. "An Input-Output Analysis of the Effects of Rising Energy Costs on Canadian Industries." Working Paper 79-1. Calgary: Canadian Energy Research Institute, April 1979.

Erickson, E. W., and Spann, R. M. "Supply Response in a Regulated Industry: The Case of Natural Gas." Bell Journal of Economics and Management Science 2, Spring 1971.

Friedenberg, W. Brent. Energy in Canada: Review and Outlook to 1995. Study No. 5. Calgary: Canadian Energy Research Institute, July 1979.

Friedenberg, W. B.; Slagorsky, Z. C.; and Walsh, A. J. "Government Incentives in Canada's Petroleum Industry." Working Paper 80-1. Calgary: Canadian Energy Research Institute, March 1980.

Friedman, Milton. Capitalism and Freedom 28 (1962).

The Globe and Mail, December 12, 1972.

The Globe and Mail, May 27, 1980, p. 89.

Green, John H. A. Consumer Theory. Baltimore: Penguin Book, Inc., 1971.

Hamilton, R. E. "Canada's Exportable Surplus Natural Gas Policy: A Theoretical Analysis." Land Economics, August 1973.

Helliwell, J. F. "Taxation and Energy Policy." Presented to the . Canadian Tax Foundation Annual Conference, 1979.

Henderson and Quandt. MicroEconomic Theory. New York: McGraw-Hill Book Company, 1971.

Imperial Oil Limited. Minutes and Evidence, Westcoast Arbitration Hearing, 1973.

Independent Petroleum Association of Canada. "Submission to the Energy Resources Conservation Board Proceeding 6157 Field Pricing of Natural Gas." Calgary: Independent Petroleum Association of Canada, 1972.

Lipsey, Sparks and Steiner. Economics. New York: Harper & Row, Publishers, 1976.

MacAvoy, P. W. Price Formation in Natural Gas Fields, A Study of Competition, Monopsony and Regulation. New York: Yale University Press, 1962.

MacAvoy, P. W., and Pindyck, R. S. "Alternative Regulatory Policies for Dealing With the Natural Gas Shortage." Bell Journal of Economics and Management Science 4, Autumn 1973.

McFadyen, H. J. *Field Pricing of Natural Gas in Alberta*. Master's Thesis. Calgary: Department of Economics, The University of Calgary, 1972.

McKie, James W. "The United States." *The Oil Crisis*. New York: W. W. Norton & Company, Inc., 1976.

Newman, Peter. *The Theory of Exchange*. New Jersey: Prentic-Hall Inc., 1965.

Ontario Economic Council. *Energy Policies for the 1980s: An Economic Analysis, Volumes 1 and 2*. Toronto: Ontario Economic Council, 1980.

Powrie, T. L., and Gainer, W. D. *Canadian Policy Toward Trade in Crude Oil and Natural Gas*. Ottawa: Economic Council of Canada, 1976.

Procter, R. M., and McCrossan, R. G. *Gas Resources of Western Canada*. Calgary: Geological Potential Committee, Open File 672, January 1980.

Quirin, G. D., and Kalymon, B. A. "Conservation and the Optimum Exploitation of Exhaustible Resources." Working Paper 73-03. Toronto: Faculty of Management Studies, University of Toronto, February 1973.

Russell, M., and Toejes, L. *Natural Gas Producer Regulation and Taxation*. Michigan: Institute of Public Utilities, Michigan State University, 1971.

Samuelson, Paul A. *Economics* 461 (6th rev. ed. 1964).

Scott, A. D., ed. *Natural Resource Revenues*. Vancouver: University of British Columbia, 1977.

Smith, Adam. *The Wealth of Nations* (1776).

Stanford Research Institute. "The Field Price of Alberta Natural Gas." Menlo Park: Stanford Research Institute, 1972.

________. "The Market Price for Natural Gas from Sources in Western Canada, 1972-1990." Vols. 1 and 2. Menlo Park: Stanford Research Institute, June 1972.

________. "The Parity Price for Natural Gas in British Columbia and the Pacific Northwest." Menlo Park: Stanford Research Institute, December 1972.

United States. Court of Appeals. Columbia LNG Corp., et al, Opinion No. 622 (June 28, 1972) and Opinion No. 622-A (October 5, 1972), 47 FPC 1624 and 48 FPC 723.

Van Meurs. Petroleum Economics and Offshore Mining Legislation. Amsterdam: Elsevier Publishing Company, 1971.

Vernon, Raymond, ed. The Oil Crisis. New York: W. W. Norton & Company, Inc., 1976.

Watkins, G. C. "Natural Gas Price Formation." Calgary, 1972. (Mimeographed.)

________. "The Formation of Natural Gas Prices." Calgary, 1973. (Mimeographed.)

________. "Regulation of the Export of Gas from Alberta." Calgary, 1973. (Mimeographed.)

________. "Canadian Residential and Commercial Demand for Natural Gas." Working Paper No. 30. Calgary: Department of Economics, The University of Calgary, May 1974.

________. "Natural Gas Pricing: Current Issues and Implications." Calgary, November 1978. (Mimeographed.)

Watkins, G. C., Walker, eds. Oil in the Seventies. Vancouver: The Fraser Institute, 1977.

Watkins, G. C., Walker, eds. Reaction: The National Energy Program. Vancouver: The Fraser Institute, 1981.

Waverman, Leonard. "The Two Price System in Energy: Subsidies Forgotten." Canadian Public Policy, Winter 1974.

Westcoast Transmission. "Submission to the Borden Commission Hearing--Price of Gas in the Field Related to Trend of Gas Discovery." Calgary: Westcoast Transmission, 1957.

CANADIAN ENERGY RESEARCH INSTITUTE

PUBLICATIONS

Studies

No. 1 The Availability of Capital to Fund the Development of Canadian Energy Supplies. J. R. Downs. November 1977 (Price $3.00, 109 pages) ISBN 0-920522-00-9.

No. 2 The Industrial Demand for Oil and Gas in Ontario. DataMetrics Limited. March 1978 (Price $3.00, 119 pages) ISBN 0-920522-01-7.

No. 3 The Effects of Rising Energy Costs on Canadian Industry. Anthony P. Ellison. April 1979 (Price $3.00, 62 pages) ISBN 0-920522-02-5.

No. 4 Potential Markets for Thermal Coal in Canada, 1978-2000: Summary and Conclusions. Canadian Resourcecon Limited. June 1979 (Price $3.00, 27 pages) ISBN 0-920522-03-3.

No. 5 Energy in Canada: Review and Outlook to 1995. W. Brent Friedenberg. July 1979 (Price $3.00, 140 pages) ISBN 0-920522-04-1.

No. 6 Energy Policy and the Balance of Payments: An Outline of the Issues. T. L. Powrie. July 1979 (Price $3.00, 61 pages) ISBN 0-920522-05-X.

No. 7 Oil and Gas Finding Costs. Russell S. Uhler. September 1979 (Price $3.00, 75 pages) ISBN 0-920522-06-8.

No. 8 Energy Use in Canada in Comparison With Other Countries. Z. Charles Slagorsky. October 1979 (Price $3.00, 91 pages) ISBN 0-920522-07-6.

No. 9 Enhanced Oil Recovery Potential in Canada. J. Philip Prince. March 1980 (Price $10.00, 332 pages) ISBN 0-920522-09-2.

Conclusions and Policy Implications from Enhanced Oil Recovery Potential in Canada, Study No. 9. J. Philip Prince. March 1980 (Price $3.00, 32 pages) ISBN 0-920522-10-6.

...continued

No. 10 The Impact of Rate Structure Change on Electricity Demand: A Case Study of Calgary Power Limited. Gerard J. Protti and Robert N. McRae. April 1980 (Price $10.00, 182 pages) ISBN 0-920522-11-4.

Overview and Summary from The Impact of Rate Structure Change on Electricity Demand: A Case Study of Calgary Power Limited. Gerard J. Protti and Robert N. McRae. April 1980 (Price $3.00, 14 pages) ISBN 0-920522-12-2.

No. 11 The Impact of a Sharp Oil Price Increase. G. E. Angevine. June 1980. (Price $10.00, 122 pages) ISBN 0-920522-13-0.

No. 12 Benefits and Costs of Oil Self-Sufficiency in Canada. J. A. Dawson and Z. C. Slagorsky. February 1981. (Price $10.00, 97 pages) ISBN 0-920522-15-7.

Client Research Reports

81-1 Models for Energy Policy Analysis: A Survey. Kenneth D. Foat, Gerard J. Protti and Gordon W. Douglas. July 1981. (Price $10.00, 121 pages) ISBN 0-920522-16-5.

Working Papers

78-1 Drilling and Field Construction Costs in the Canadian Petroleum Industry. Gordon M. Engbloom, Confer Consulting Limited. January 1978 (Price $3.00, 83 pages).

78-2 Some Supply Price Estimates for Synthetic Crude Oil in Canada. Z. Charles Slagorsky. April 1978 (Price $3.00, 42 pages).

78-3 Past and Future Energy Costs in the Canadian Economy. Anthony P. Ellison. April 1978 (Price $5.00, 136 pages).

78-4 Canadian Electric Utility Industry Costs, 1960-1990. Gerard J. Protti. May 1978 (Price $10.00, 218 pages).

78-5 Enhanced Oil Recovery Potential in Canada - A Methodological Preview. J. Philip Prince. June 1978 (Price $10.00, 184 pages).

78-6 Regional Energy and Production Data for Canadian Manufacturing Industries: 1962-74. Robert N. McRae and Alan R. Webster. July 1978 (Price $5.00, 106 pages).

78-7 Regional Demand for Energy by Canadian Manufacturing Industries. Robert N. McRae. October 1978 (Price $5.00, 132 pages).

...continued

79-1 An Input-Output Analysis of the Effects of Rising Energy Costs on Canadian Industries. Anthony P. Ellison. April 1979 (Price $10.00, 246 pages).

79-2 Potential Markets for Thermal Coal in Canada, 1978-2000. Canadian Resourcecon Limited. June 1979 (Price $15.00, 321 pages).

79-3 Inter-City Comparisons of Canadian Household Energy Costs. Darcy-Gail Ackerman. June 1979 (Price $3.00, 77 pages).

80-1 Government Incentives in Canada's Petroleum Industry. W. B. Friedenberg, Z. C. Slagorsky, and A. J. Walsh. March 1980 (Price $3.00, 43 pages).

80-2 A Regionalized Electricity Model: Preliminary Analyses. Kenneth D. Foat and Gerard J. Protti. April 1980 (Price $3.00, 61 pages).

80-3 Alternative Future Supplies of Oil in Canada and Their Costs. Z. Charles Slagorsky. May 1980 (Price $3.00, 36 pages).

80-4 Prospects for Reduced Oil Consumption in Canada. W. B. Friedenberg and A. J. Nixon. May 1980 (Price $3.00, 34 pages).

81-1 Crude Oil Supply and Demand: Major Issues and Alternate Scenarios. Douglas J. Haughey. July 1981 (Price $7.00, 158 pages).

81-2 Natural Gas Pricing in Canada: An Economic Analysis. Andrea J. Nixon. October 1981 (Price $5.00, 116 pages).

Conferences

Markets for Canadian Uranium. Proceedings of a Seminar Held on October 25, 1979, Calgary, Alberta. (Price $10.00, 89 pages) ISBN 0-920522-08-4.

Annual Report

Annual Report of the Board of Directors for the Period April 1, 1980 to March 31, 1981.